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BEFORE THE ARIZONA CORPORATION COMMISSION

2004-2013 BIENNIAL TRANSMISSION ASSESSMENT WORKSHOP) E-00000D-03-0047

) SPECIAL OPEN MEETING

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ACC

ORIGINAL

AGENDA

BE IT REMEMBERED that the above-entitled and numbered matter came on regularly to be heard before the Arizona Corporation Commission in the Industrial Commission Auditorium, 800 West Washington Street, Phoenix, Arizona, commencing at 9:00 a.m. on the 30th June, 2004.

BEFORE: P. JEFFREY PALERMO
Executive consultant, KEMA, Inc.

SEDINA ERIC
Principal consultant, KEMA T&D Consulting

JERRY SMITH
Arizona Corporation Commission

APPEARANCES:

Panel 1:

Jeff Miller - CAISO
Rob Kondziolka - SRP
Gary Romero - SRP
Ken Bagley - RW Beck
Mark Etherton - KR Saline

Panel 2:

Bob Smith - APS
Rob Kondziolka - SRP
Bruce Evans - Southwest Transmission Cooperative
Steve Mavis - SCE
Perry Cole - Trans-Elec

Panel 3:

Jerry Smith - ACC
Rob Kondziolka - SRP
Bob Smith - APS

APPEARANCES:

National/Regional Transmission Issues Panel:

Charlie Reinhold
Steve Cobb
Mike Neal
Ed Beck
Bruce Evans

CECELIA BROOKMAN
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MR. JERRY SMITH: I'd like to call this special open meeting of the Arizona Corporation Commission to order. This is the time and place properly noticed for the Commission's biennial transmission assessment workshop.

My name is Jerry Smith. This microphone is not working so if you can't hear me raise your hand and I will speak louder

As I can tell, this is going to be a fun day.

And we have a very extensive agenda today, and let me begin first by taking care of a few housekeeping matters. We have the room until 5:00. The agenda is a long one, and as we go through the agenda, we may ask the presenters to compress their material if we're running short of time. Knowing the number of files that I just loaded this morning, I think we're going to have our hands full.

If you don't know much about Arizona's transmission system coming into the room today, I suggest by the time you leave, you will either be confused or extremely informed. Or maybe both.

(Sound heard.)

MR. PALERMO: That was my reminder to ask everybody who has a cell phone to put it on silent. Excuse me.

MR. JERRY SMITH: That's timely. And in fact, I need to advise you that we do have a court reporter today, and so as we have interaction in the meeting, I'm going to ask you if you're in the audience, be sure and speak up and give your name, so that the court reporter can properly record the information that you're trying to convey.

Also, I want to point out that we do have one Commissioner in attendance already this morning. There may be others that join us throughout the day, or their policy advisors.

And the purpose of this meeting, this workshop, is to gather information about the transmission system in Arizona so that Staff and our consultant can do an assessment of the reliability of the system. And we have a consultant that is supporting Staff in this process, and I'd like to introduce them at this time.

It's KEMA Consulting, and with us from KEMA Consulting this morning is Sedina Eric, and Jeff Palermo. And I have advised them that this is a friendly group, that they can count on getting frank answers, and I'm sure you won't disappoint me.

They also, following today's meeting, are going to have the challenge of trying to write the report based upon what we gather information wise today. So there may be occasions when they need to contact those of you in attendance to get some clarification of information that they have on hand.

With that, I'm going to turn the meeting over to Jeff Palermo, who is going to facilitate our panel presentations today, and with that, Jeff, they're all yours.

MR. PALERMO: Thank you very much. There's no need to stand at the podium. Those of you that know me know I can't stand at the podium because I'll wander around. I will try not to be long.

With that in mind I'd like to ask the first panel to go ahead and start coming up, because I'm not going to make a long introduction, and that way we can get right to stay on schedule. I'll try and keep us focused that way, so that everybody will have a chance in the course of the day to present the material that they would like to present for recording today.

This first panel we expect to be finished by 11:00, so I should turn and say that this way. Excuse me. We expect the first panel to be done around 11:00 this morning.

I also remind everybody again that with the panel, if each of the panelists would introduce yourselves, name and company, for the court reporter, I think that would help. It will help me. Maybe all of you know everybody already and that's not so bad.

We're very pleased to be here, Sedina and I and KEMA Consulting. This is a good process to be a part of. Just in recent months, she and I have been a part of transmission issues in all four corners of the United States, Connecticut, Florida, the northwest, now Arizona and in the midwest.

And it's really nice to see the collaborative process that's being undertaken, and from the comments that I've heard, that you've had a good experience with this. It's really a much better way to get projects moving and projects going in the right direction to do it in a collaborative way. You still end up having some adversarial things that happen at the end when you actually go to build and get things committed and you're putting them in rate base, and environmental issues. But it's still a lot better to start with a plan and a blueprint that's been worked out in cooperation with utilities and the Commission and Staff.

It's really very important. It makes for a much more effective plan. It makes for things to proceed more smoothly. I mean smoothly in the sense that you tend to remove issues that, when you started out with a legal adversarial issue, the lawyers -- I'm not sure how many of you here are lawyers -- but the lawyers' job is to protect their client so they bring up every possible problem and every possible difficulty. And when you start on a collaborative approach, you can remove a lot of the false issues, and just get more focused on what's left and what's real.

So my complements to you collectively, the utilities in Arizona, and the Commission and the Staff for using this procedure. I don't think I've seen it for transmission done as well as I've seen it here in Arizona.

Having said that, recognize that we are the consultants for the Commission and the Commission Staff, and our job is to find what's good and anything that may be missing or false that are there to ask questions to try and understand what's going on with the transmission system in Arizona, and what the needs are. And we see our role as if there's something fatal, to try and bring it up again in a collaborative sense. If there's some real problem, I think you guys in the utility industry are going to want to know, too, if there's something you've missed and we see it, I'm just assuming you're going to want to know about it.

And our role is not to embarrass. I'm just trying to let you know the context in which we'll be working. I think we're trying to work with the utilities as representatives of the Commission to try and come up with what is the best transmission plan for Arizona. We're not here to prove ourselves smarter or anything like that.

With that, then, I would like to turn it over to the first panel, with one additional comment, that we're here to learn and to understand better what's been done, what's being done. There's a wealth of material and we haven't read it all yet, and part of what we hope to learn from these panel sessions is what things we need to focus on a little more closely in our reviews for the report we're preparing.

So without any further comment, I would like to turn it over to the first panel, except they don't appear to be quite ready yet. So as soon as they are -- okay. So if you would like to introduce yourselves. Why don't we go left to right, regardless of the order that you'll present yourselves in, name and company, so the court reporter will have that. Okay. Thank you. And thank you for your attention.

MR. BOB SMITH: My name is Bob Smith, and I'm the manager of transmission planning at Arizona Public Service. I think my participation on this panel is because I also co-chair the STEP group which Jeff is going to talk about, and I'll follow up a little bit with the

Arizona involvement.

MR. MILLER: I'm Jeff Miller with the California ISO.

MR. KONDZIOLKA: And I'm Robert Kondziolka with Salt River Project. I'm manager of transmission planning and I'm on the panel as the new chair of SWAT.

MR. MILLER: I guess I'm first up, so why don't we get started. First of all, let me thank Jerry for inviting me down to talk today. I'm going to talk about two things: SSG-WI and STEP. It's always a pleasure to come to Arizona and talk with you folks. I was thinking about, I found I actually spend a lot more time working with the people in Arizona than I do with the people in northern California. I'm responsible for the southern portion of the ISO grid. But when you think about it, that makes a lot of sense. Southern California and Arizona are much more tightly interconnected upon each other than southern California and northern California, so from my perspective, that's a good thing, because Arizona and southern California get along much better than southern California and northern California. I'd much rather work with you guys than the people in the north or the south.

Let's talk about SSG-WI. Some of you may not know what that is. It's Seams Steering Group, Western

Interconnection. It was formed originally when there were three RTOs proposed for the west. It was a way that they could work together and make the west function as one RTO.

Since that time, it's become clear RTOs aren't going to develop very quickly, maybe not at all. So SSG-WI broadened its membership up to anybody that was interested, and essentially formed a planning base for the entire western group interconnection.

One of the first things they started on was to complete a study which was completed last October. The study looked at two time frames, one looking out five years, which at that time was 2008, and another looking out 10 years. The five-year-out case was mainly to look at just generation that's out there, congestion on the systems, where are the problems that exist today that we can do something about.

The 10-year-out case was done more for the policy people. That looked, that case looked at three major development scenarios from primarily coal development, natural gas development, or heavy renewables development, and identified the transmission impact so that the energy policy people, if they wanted to go down one of those avenues, they had an idea what would be required from a transmission perspective.

This graphic, I'm not going to go through it in detail, but it gives you a good overview of the areas on the whole western interconnection where in the 2008 study there was substantial congestion observed. You can see between southern California and central California, this is the notorious Path 15. There's quite a bit of congestion. There's a new line being constructed as we speak that should be in service hopefully as a Christmas present this year, right? So that congestion will be substantially mediated.

Then you can see between Arizona and the southwest, there are quite a few of these little boxes which indicate congestion, and that's really been the focus of the STEP group I'm going to talk about in just a second trying to address that congestion. There's substantial congestion elsewhere in the grid, but mainly, almost half of the congestion in the entire interconnection was in the southwest, between Arizona and California.

Overall, the congestion was about 110 to 140 million a year. That was the cost, increased cost as far as looking-forward costs, variable O&M costs, mainly fuel. And as I mentioned, about half of that was in the STEP area.

Now, when they looked ahead to 2013, they came up with three scenarios. They developed three scenarios I mentioned earlier: Gas, coal, renewables. And we developed transmission plans for each of those scenarios, just rough transmission plans, nothing you could go out and build right away, but it gives the policy makers a pretty good idea of what would be required for the gas scenario. The generation was located primarily near load centers. We had about 1300 miles of new transmission at a cost of about $2.6 billion.

We had a coal scenario. The coal fields are located fairly remote from the main load centers. There, we had quite a bit more transmission, 7,600, at a cost of about 16.7 billion. Those numbers seem awfully large, but when we looked at the potential savings to the end-users, ratepayers, we found that that could be a cost effective investment for the ratepayers, because coal generation is so much less expensive than natural gas. And this was back when we were looking at dollars for gas, and of course now we're looking at much more expensive gas.

For the renewable scenario, it was kind of in between the gas and the coal scenario as far as transmission requirements. There was a lot of wind generation up in the northwest over in Wyoming, Montana, and the cost of bringing that into the major load centers was fairly substantial, about 6.7 billion, and about 3,300 miles of transmission. So we pass that information on.

We're not sure how it's going to be used, but it was asked of us to provide it, and we're hoping that it's useful to the energy policy people.

Our current efforts in SSG-WI are, one, to develop a west wide production cost database. That is the tool that we use, the computer program that we use to simulate the future interconnection, to figure out how much money these transmission investments are going to save. We want to try and get an entity to maintain that on a continuous basis so that STEP and SSG-WI and SWAT and all these groups have the data that they need to conduct their studies and coordinate on an interconnection wide basis.

There's actually a proposal going before the WECC next month that would have WECC take over the maintenance of that database. This fall we're planning a two-day workshop, maybe three days, to talk about how these studies are conducted, what the models do, how you interpret the results. For anybody in here that's responsible for trying to understand what these studies mean, this would be a good thing to go to. They will be free we think at this time, and you can come up, it will probably be in Portland, come spend a couple days and hopefully learn a little bit from some of the experts across the interconnection about these types of economic studies and what they mean, how to interpret them.

Then once we get a database developed, we want to start doing studies again in SSG-WI, we want to look at a realistic future scenario case instead of these bookend cases, instead of like maximum coal, maximum renewables, maximum gas. We want to develop a reliable case, one we think is pretty reasonable, study that and see if we can get started on some major projects that seem to make sense from an interconnection wide perspective. That is it for SSG-WI.

Let's move on to the subregional planning groups. As soon as SSG-WI started, when we first started doing the analysis in SSG-WI, we found that looking at the whole interconnection was a big job, a really big job, and it was hard for SSG-WI to develop plans for the overall interconnection, so some groups started developing to pull off pieces of the interconnection and look at specific problems. The southwest was being very proactive on that. They already had a group called CATS that was active and doing that well before SSG-WI was even formed, and Rob will talk about that when he talks about SWAT.

But in some areas, those groups did not exist before SSG-WI. There's one in the northwest called NTAC. I won't go through these in the interest of time. There's one in the Rocky Mountain area that's received a lot of press, actually had several governors come to their first meeting to kick it off. It's a very high profile effort. We're looking at developing coal resources and potentially exporting it outside that area. Then we have SWAT, which Rob is going to talk about, then we have STEP, which Bob Smith and I are going to talk about.

Let's go to STEP. The purpose of STEP was to bring together all the interests in that area of the interconnection. And that area is essentially Las Vegas, Phoenix, west, southern California, and a little bit of northern Mexico, bring together anybody that was interested in helping develop an overall transmission plan for the area.

And the goal was to develop a common vision for the transmission grid so that it would provide a couple things. One, by getting all the different entities together and have them work together, we felt we could develop a better plan than if an individual tried to do it on their own.

Two, we thought that getting that kind of a broad consensus would make it a lot easier for the plan to move forward. Transmission lines, of course, are very difficult things, particularly in California, to actually bring it into being, so we thought having broad consensus would help that process. And it's worked. I think we can say at this point that so far, STEP has been very successful in doing this.

I'm going to get a little bit technical here just for a second. Most of the people in the room this is not technical at all, but there may be a few of you that are maybe getting a little too far into the nuts and bolts. What I'd like to describe is just generally how we set up limits on the system, and give you a glimpse of the studies that we've done and how the existing limits are constraining the system, and what would happen if we relieve those lines. So I need to describe what a couple of the limits are.

This diagram shows the major load areas. Arizona, not only in Phoenix, Nevada, and Las Vegas in this diagram, southern California, and we have Mexico as well. Those yellow, those mustard yellow lines, those are the main 500 kV lines that tie this whole area together. We have a couple paths that the operators use on a daily basis to monitor flows in the interconnection. We have one called SCIT, southern California import transmission, and it's just a sum of the flow on all of the different lines that this dotted black line crosses over. So if you sum up all those, you get one number called SCIT, southern California import.

Over here, hanging out of Arizona up into

Nevada or into southern California we have one called East of River or EOR, and it's a cut plane of all those. It's the sum of the flow of all those lines, and that's east of river flow.

This diagram shows the actual operation of the system. On this axis we have total southern California import, total SCIT. On this axis we have total East of River. All those -- that black thing in the center is actually a bunch of dots, 8,760 dots, one dot over every hour of the year. This is actual system operation data from March 1st of 2003, to March 1st of 2004, so fairly recent data. And it shows how this system actually operated.

You notice we aren't really getting out to the full SCIT limits, which I've drawn here in yellow on the board. Typically, in day-to-day operations, there's other things that constrain the system, and you can't get to these maximum limits which are shown on the diagram. So this is what exists today.

Now, we did a study looking at 2008 and said what happened if we just said we're not going to restrict the system to what SCIT is limited to or East of River is limited to, we're just going to let it go to where it's most economic for the system to operate and that's where we ended up going. You can see the East of River flow, this is direct output from the computer program which we think is pretty close. These tools are still pretty new to the interconnection, so there may be somewhere I can't guarantee where these results are perfect, but I think it gives you a good indication that there's a lot of economies to be gained by enhancing the transmission to East of River, and enhancing total southern import transmission.

I'll just go back. So this is existing system operation. This is what our studies show will be most economic in 2008.

One other interesting result we can get out of the simulations is gas consumption. This is something that Jerry Smith asked us to report on. We had to change the program to do it, but the vendor, ABD, was able to do that fairly efficiently so we went ahead and did it. We can see here, this isn't for the exact case I showed you before. This shows a series of upgrades, mainly to the East of River interface, and it shows how gas consumption would change in each of those regions. Arizona is the blue bar. You can see the natural gas consumption in Arizona goes up and natural gas consumption in southern California goes down. That's to be expected. The old clunker plants are over on the California coast. The new efficient gas plants are located mainly out by Palo Verde or outside of Las Vegas.

A useful piece of information for policy people or the people that do natural gas. SSG-WI, STEP, they don't get involved in natural gas issues. We really leave that for others to deal with.

Now I want to talk about what STEP developed. They have what's called a short-term upgrade plan. These are things that we felt could be done very quickly within a couple years. No new line permitting. That was the major restriction here because new lines take time, a lot of time to permit. At least in our state. I've heard some real success stories over in Arizona, which is amazing, but in California it takes years and years. So we try to come up with a way we could implement some upgrades quickly, then we have some longer term projects, new lines, Palo Verde, Devers No. 2, and a new line to San Diego. I have a map which shows some of these upgrades.

We have two lines. Actually, there's four, maybe five lines that's shown in green on this map, where upgrades can be made in the short term that free up a fair amount of transmission. These upgrades are series capacitors. I have a picture of a series capacitor to help explain what that is.

We're going to provide something called

voltage support in southern California near Palm Springs, at a substation called Devers. We have the longer term new lines, Palo Verde, Devers No. 2, and new lines into San Diego. The lines into San Diego are mainly for reliability needs in San Diego more than economic needs. But they do have some economic benefit.

Here is a picture of a series capacitor. Most of you know what those look like. This one, I went out and took this, this is a Nevada power line, Crystal substation, brand spanking new, nice and shiny so I like this picture. They don't look as good 10 years later.

This is a series capacitor. We just approved, in California at least, moving forward with a number of these banks, upgrading four of these. One of these upgrades would be the responsibility of Arizona Public Service, and this was all developed through STEP. So the mechanisms and the approvals that are necessary, at least some of the large ones, some of the major approvals in California have already been completed for some of these upgrades.

At Devers, the dynamic voltage support is required. The leading contender for that right now seems to be a static var compensator. We may be able to get away with something less than that. People often say that the power grid's still being develop the way it was 50 years ago. That's really not true, but we do take advantage of the latest technology.

This is a power electronics device. This building back here is filled with power electronics, and all the cooling equipment to keep those power electronics cool, and shunt capacitors, and shunt conditions. More traditional, this outage responds to outages on the system, enables us to get more out of the existing system. An outage happens, it responds instantaneously, holds the voltage up so we can meet the reliability standards.

This is a phase shifting transformer. This is a Salt River Project transformer, this is at Perkins. Phase shifting transformer, putting in one of these probably at Imperial Valley substation, this is improved upgrade. It won't be quite as big as this one. Instead of 500 kV it will be 230 kV, but we'll be adding one of those. So that's it for the STEP projects.

Then as far as where STEP is going now, one is we're pushing as fast as we can to get those short-term upgrades in. The plan now is to have them all in place in the spring of 2006. We're starting to look longer term, looking out 10 years instead of just five. When you're looking out five years you're really just reacting, you really aren't planning.

So we're trying to get from that reactionary mode into a planning mode. We want to look longer term and we want to work more closely with SWAT and with SSG-WI and other groups to make sure we're well coordinated. And the tools that are used to figure out the value of these projects are all still really, they aren't new tools, but they're maybe being used in a different way than they have originally been planned for. So we're having to make some changes with tools, and that's a long, slow process, but we're embarking on that.

Okay, I guess -- are we going to hold the questions till the end?

MR. PALERMO: Yes, we are.

MR. MILLER: With that, we can move on to Bob.

MR. BOB SMITH: What I really want to do is reinforce Jeff's comments on STEP, give you an excellent presentation, give you an overview, but I want to emphasize the Arizona involvement and impact of the STEP efforts.

Jeff is absolutely correct as far as the collaboration we've seen in STEP from both Arizona representatives and California. I think when Jeff opened up, he told about the importance of collaboration, and I've often kind of wondered how the planning meetings went when the people in California first thought of this regional transmission planning group and the need to have some Arizona involvement. And one of the things that obviously worked was the idea of having a co-chair from Arizona along with the co-chair from California. Originally, Harlow Peterson, who just recently retired, was the co-chair and worked for several years I think with Jeff and Army Perez, and recently I agreed to try and at least fill Harlow's rather large shoes. Those of you that know Harlow, as you can imagine, that's literally and figuratively. Literally, I don't think I'll have a problem.

I think the other idea, whoever came up with this idea was just brilliant. The other idea they have to ensure that people would show up, participate and we would have a collaborative process, is to hold every meeting in San Diego, and it's worked very, very well. If people don't show up it's not because they have a better place to go.

There are three projects, two of which Jeff mentioned that STEP is at least discussing that have a direct impact on Arizona because some of the facilities are in Arizona.

The first is the short-term upgrades that he discussed. And a little less than a year ago I actually agreed to chair a group to implement these short-term upgrades. And I think what went on there, what the planners realized, these are good plans, but somehow we have to have these things actually happen. And they heard I was actually in operations for a number of years so they thought maybe this ex-operator could actually get something to happen, so I've been working through implementing the short-term upgrades. I'll talk a little bit more about those.

Obviously if a second Palo Verde/Devers line is built that goes across a significant part of Arizona, then third is something that Jeff didn't mention, it's sort of an alternative, if you will, to a second Palo Verde/Devers line, it's a larger scale upgrade involving the series capacitors on really all of the 500 kV lines into California from Arizona, and probably some additional reactive support like Jeff mentioned. Salt River has come up with this project and is actively sponsoring, and it has been discussed within the STEP forum.

Jeff mentioned a lot of these, and this is just sort of the list of the components of the short-term upgrades which will add about 500 megawatts of transfer capability to the east of the river system or the EOR Jeff mentioned.

Maybe more importantly, as Jeff showed you on the graph, the system really doesn't operate near 7,500, 7550, because there's some other limitations, specifically the thermal ratings of the two southernmost 500 kV lines, the Hassayampa/North Gila and the Palo Verde/Devers lines. This project will significantly upgrade the series capacitors on those lines and increase the thermal capability of those lines effectively beyond the 500 path rating increase. So I think not only do we get some scheduling capability out of this project, but we sought a lot of the operational issues that don't let us attain the full capability of the system today.

So the SWPL stands for the southwest power link. It's a short-term for the Hassayampa/North Gila, North Gila/Imperial Valley onto Niguel, the southernmost part of those lines that will have capacity. Also a second series transport is needed at the Devers to accommodate the transformer.

As Jeff mentioned, both the control devices, voltage support devices at Devers. Small upgrade on the 230 kV system west out of Devers, and phase shifter that Jeff mentioned out at Imperial Valley. This is sort of a schematic of all of these upgrades. I'm not going to go through all of them, but I did want to show that one of the complexities of this project is that it's not all owned and operated by the California ISO. The California ISO can't direct the participating utilities to make this happen. You have two other owners in the southern line, APS and Imperial Irrigation District, IID. And in fact APS is the operating agent of the line from Hassayampa to North Gila and the North Gila substation, so project upgrades would be required to be made by, again, APS with these capacitors and North Gila/San Diego with the capacitors at Imperial Valley and Southern Cal Edison, with the capacitors on the Palo Verde/Devers, line as well as the transformer at Devers and the upgrade on the 230 and also the ramp support. There's several entities that really have to coordinate all of their efforts to make this happen.

The progress that we've made to date, there's quite a bit of debate over exactly how high we should go with the rating of the series capacitors. You can show from technical studies from a load flow standpoint you won't exceed X, but the economic studies say you really ought to go to Y. And we had some debates over time, but we finally have come to agreement on what these ratings should be. The STEP group officially sponsored these upgrades at the May 27th meeting, so we have consensus of STEP that we should move forward, and as Jeff mentioned, the California ISO board approved the upgrades on June 24th. We have a draft memorandum of understanding between all the parties, the owners that deal with issues like allocation of the capacity increase, cost construction responsibility, and that draft is toward the end of June this year.

If we're going to move from here, what we need is to fine tune the specific voltage support requirement, and that's being done within the WECC rating process. Once we know how much voltage for it, we need to figure out who's going to pay for that. And ultimately we'll need to obtain a WECC path rating increase through the peer review group process, finalize the MOU, order the equipment, then it's just a matter of doing the work.

Last thing I wanted to mention was, and this further illustrates the cooperation, really, between Arizona and California within STEP. One of the subgroups that STEP designated to get some of this work done was assigned to sort of finalize, if you will, the plan of service for the 500 kV line from Arizona to California, which currently the only line out there is the second Palo Verde/Devers line. There was a subgroup active to try and figure out how that would fit in with everyone's plans, do the best thing for the region.

A similar subgroup was formed when CATS formed into SWAT. Rob is going to tell a lot more about that. It was a technical group to look at transmission planning within Arizona to the Colorado River, and along the Colorado River north and south for needs of the various participants.

At the last STEP meeting it was discussed really these two groups are looking at similar projects, for the most part are the same people meeting, and I think once everybody agreed to continue meeting in San Diego, we did agree to consolidate these two groups. And you're going to hear more about this I think from Ken Bagley who chairs the SWAT subgroup, which really the STEP group sort of merged into that.

And that's all I had planned. Thank you.

I guess, Rob.

MR. KONDZIOLKA: Well, good morning. I've heard a lot about SSG-WI and STEP. As most of you know, this is the third biennial transmission assessment. And as I reflect back on the second biennial transmission assessment just two years ago, a lot has changed. When we met two years ago, there was no STEP, there was no SWAT. Charlie Ryan had made a presentation on the formation of SSG-WI. It was just getting started.

And as you can see, a tremendous amount of work has been accomplished in just two years. And this evolutionary process, I think lends itself to the origins of SWAT. And I think it's important to note, because this is the number one question that always gets asked, and it goes back to Jeff's introduction on the collaborative process that is being witnessed out here in the southwest, and that is, why does it work? Why should it work? What is new, what is different? And I think it's back to the founding purpose of SWAT, and it's very simple here, and to develop a high level transmission plan that maximizes the regional benefits while making efficient use of the existing transmission system.

It's words, but what does that really mean? And I think everybody in this room here is here because they have some interest in transmission. We all recognize that transmission is a very scarce resource, much scarcer than we want it to be. We all know that any new transmission is difficult and challenging. There's nothing easy about it. Jeff spoke of how difficult it is from a time perspective to get new transmission built in California. When we talk about things in a five-year time frame, as Jeff noted, that's near term and that's just to get started. When we talk about any significant transmission conditions we're talking five to ten years from when you start talking about it. And there's a lot of money that goes into it.

I think the stakeholders in this region have recognized we need to work together. We all have the same common interests. We're not going to be overbuilding transmission by any stretch of the imagination. To even get the next link put into place will require the cooperation of a lot of interests of the parties, and there's no need in trying to eliminate ideas or the opportunity to allow other parties to participate. And I think that is why you see where we are today, and I think that is why we're seeing success at SSG-WI, we're seeing success at STEP and we're seeing success at SWAT.

Those are kind of introductory comments. I do need to make a comment, and I won't go into much more. You'll notice here with SWAT we have the really fancy logo, and we're really proud of that. At the last STEP meeting I sort of challenged Jeff to come up with a logo because we haven't seen one from them yet. And I'll refrain from the comments I made about the type of logo that I thought it might be.

But so we talked about origins. Two years ago, all we talked about from a regional planning perspective was CATS, and at that point in time, CATS was two years old. What I would really like to comment on, because there's a few new people in here that may not know that story, and that is the origin of CATS. The Central Arizona Transmission System has its origins with the Power Plant and Transmission Line Siting Committee, and the first workshops sponsored to address transmission issues.

When '99 was going through, there were a number of applications for generators to interconnect into the existing transmission system. And as you can imagine, there were a number of questions about the applications about how it fits into the grid. None of the applications included any transmission additions. So the obvious questions were raised: Is the existing transmission system adequate to accommodate this interconnection, and is it adequate to accommodate all the other generation additions that were coming in, that were already being filed. If not, what type of transmission additions were going to be required? Where should they be built? Who would build them? How would they be coordinated? Would it be the utilities or would it be the generators? How would we know that from a large scale perspective, that it made sense to do what was being proposed? How are we trying to move energy from the plant to markets? What markets are we talking about?

Those are very philosophical questions and also very challenging questions from a transmission perspective, but when we had that first workshop, we were able to present 10-year plans. We weren't able to answer very directly those type of questions, and that was sort of a spark for saying we need to work together, we need to be able to come back to the bodies that are asking these questions and present some type of formulated plan. And that's really where CATS starts with.

You know, the rest of it is history and I won't go through every detail from there. It started small, it started with just the Commission and the utilities. But within two months, we had participation by the generators, and then within two months of that, it had participation by most other entities that had an interest in transmission. Marketers, those who did scheduling, those who were doing other types of planning and that led to the great success because when a report was developed, it incorporated the different ideas and concepts not just from one aspect, not just from the utility aspect, but from all the aspects.

CATS has moved along, and there was a Phase I report that was issued after about one year, and then the following year, after two years, there was a second report, and I'll touch on Phase III in a moment.

Then as we were moving along, as I noted here in a couple steps, Harlow Peterson, who was our former chair of CATS and SWAT, we had discussed what can we do to improve this. We had been working here in Arizona. It was obvious that we needed to look at more than just central Arizona and this demand. Looking at energy from Palo Verde over to the southern California area in the SSG-WI studies was a glaring issue, and we didn't have any forum set up to manage it. And that's when the offer was made to Jeff Miller and to Army Perez of the Cal ISO about forming something. And I forget some of their first names. I think we had CART and something else.

We eventually get to a two step. It gets better than CART. I think we've got a better logo than CART. The point being, a seed was planted. CATS blossomed. It needed to grow, it needed to have more opportunity.

So those first two reports that were done through CATS didn't look at time frames, they really took a look at regional assessments and needs. And this long-term master plan, we'll touch a little more on the chairman of these study groups, but this master plan came out of it.

Getting back to the second biennial transmission assessment, and that is what do we know about the timing of these projects, we know that it needs to be done, but is it 10 years out, 15 years out, 20 years out? So the Phase III report was looking at two key elements. One was, it wouldn't be APS doing study work, SRP doing study work, TEP doing study work, coming up with 10-year plans, saying this is how they generally worked together. It was those three plus everybody else, southwest transmission, the CAP, looking at all of those needs, coming up with a common base case that we all would use to study our plans and see how the plans reacted when we added the 10 years' worth of load. That way, when everyone submitted, the Commission was able to evaluate that impact knowing the commonality was incorporated. We didn't have to ask did this project impact this other project. We know the answer on that.

Now, we had been moving along that effort to try and draw that to a total statewide basis, and it was again evident from the parties here working with Bob Smith, working with Jeff Miller, and working with others, even from that SSG-WI perspective that Jeff touched on, is CATS was not broad enough.

And we then discussed within that CATS environment what do we do to make this right, do we do what. And through a series of conversations from the stakeholders at the meetings, it was we need to have a more broad region. It was generally a natural fit to look at what's called within the WECC, desert southwest region, which is all of Arizona, New Mexico, southern Nevada, and it also had some fringes into Colorado, but that was a natural fit.

And the other part was we didn't want to see CATS made into SWAT. We said we need to take a different direction, we have different people, we have different interests. And SWAT then had the opportunity to take a look at some of those other subregional groups that Jeff mentioned. They had gone through some growing pains and we were able to evaluate what was the RMATZ group doing, what was STEP doing, what was the NTAC group doing.

We took a look at that. I think we drew upon the best principles each of them had developed, and within that group called the SWAT territory, Arizona, New Mexico, southern Nevada, put together our own principles. They don't match CATS. It's not CATS with just a bigger footprint. It's different, but it has some of the guiding principles that I touched on as to why we have a purpose in doing work.

A key to it is being open, and it is open to everyone. These are some of the key categories we saw each of the stakeholder groups falling into. Even if we didn't list any subgroups, it really wouldn't make any purpose. This was done more for organizational purposes, in case we needed to have certain types of work done, it may be convenient to have these categories in here.

I don't want to elaborate too much on the principles, but key of the items are its openness. And again, it is in our business interests to do it that way, because remember the old Holiday Inn commercial where the best surprise is no surprise. Same thing. What you don't want to do is move it to two or three years of work, and find out that you haven't addressed something. That would be the worst type of result.

That second bullet, because of the caliber of people we have, and the interests that are there, we don't see the group as being a policy maker, but it is a good forum for having policy issues evaluated. And we have this opportunity, as we talk about some of the new issues, one of those being some of the potential for renewable generation in significant quantities, much greater than previously planned. We have an opportunity here to evaluate what's the best way to address that, how you incorporate large amounts into a single control area, and is that feasible. We all have heard plenty about collateral planning.

And then the last one is the issue of, at least here in Arizona again, making certain that we provide that common foundation for 10-year filings, so that when these plans are submitted -- and the ones we'll talk about later this morning or this afternoon -- we know that they had a common base case which underlied the study work.

We talked about the type of studies that are being done, and this is a repeat, but important on that second and third bullet. We're not going to come in as a group and say this is the plan. We're going to study any type of proposal, but we're always going to look at alternatives. I think it's very, very important to be able to answer the questions what else, what if, and we need to know what else might work, what else might be feasible.

I think in all the study work you see here that I would say the thing we're going to apply, as with all the other studies with the WECC standards, guidelines, procedures, policies, then consensus, that's probably the biggest challenge, is how you achieve consensus with that broad of a group. And at least today I'm happy to report that pretty much it has not been as challenging as you might think, because it has been more driven by the technical aspects, and there are times when the technical issues are debated and then they are heated debates. But in general, the straightforward technical responses kind of win out. It doesn't get too engaged in an opinion.

And then one of the challenges we have here when we talk about common database now, not just amongst ourselves within SWAT, it is to have a common database when we talk about STEP, when we talk about RMATZ, when we talk about NTAC or SSG-WI. So there is a very concerted effort being pushed through, how we can make certain that our study group in SWAT has a common base case as the

RMATZ group, STEP and NTAC. Then if you don't communicate your information it's no good, so it needs to be reported. So in addition to having the information posted on the website as we move forward, there needs to be reporting in the form of reports that everybody can have access to.

Jeff showed a map of the study groups, so this is just a repeat of that. This was intended to be more geographically oriented, and it's interesting to point out just a couple items here. This overlap, you see SWAT coming like this. And you see STEP like this. We've worked, as Bob had noted, with this area of overlap, and over the last year it became evident we needed to do something, so we don't have meetings of the same thing.

I will let TEP address that in more detail, but it's worth noting as part of SWAT we thought it was worthwhile to allow one of the sub study groups to support two different subregions versus having our own study group.

The other one in here, which I listed here, was this CCPG. I think that stands for the Colorado coordinated planning group, which is sort of an underlying area in RMATZ. And they are an older organization and have been operating very quietly. I think it's worth noting that they've been out there for a while.

This is a map of the sub study groups within

SWAT. You'll have an opportunity to hear from the chairman from each of these groups. My screen certainly looks a lot sharper than this screen here. As I look here, this is the first group, Colorado River transmission study group. This green one here is the old CATS group called the CATS EHV, for extra high voltage study group. And also there's this blue within this, and that's the CATS central Arizona high voltage study.

To make a distinction, the EHV is looking more at the 500. Then of course if there's 345, it interacts, whereas the high voltage is looking at the 230 and below, within that area, you'll hear from the chair about some of the significant underlying issues. I know that the higher the voltage, it's sort of a sexier opinion of getting involved with it, but with a lot of that, if you don't address the underlying system you're not going to have an overlying system.

And then we have an area here along the Arizona-New Mexico border, and it has an obvious name of the Arizona-New Mexico EHV study group. Its primary mission is to look at really not so much load in here, but all this new coal resource in here, and how that coal resource will be integrated in the transmission system or expanded into the load centers.

Lastly, we have this New Mexico study area.

You can see it's a fairly large area, again not as much load, but there are some very significant issues that some of you are maybe familiar with. One is down here in the El Paso area. You talk about import constraints, I think that that's the most highly constrained area in all the western interconnection. I believe that's correct. And we do the SSG-WI studies. That's where the highest pricing goes towards.

The northern area here, where Albuquerque is, you'll notice there's a lot of transmission to the north and west, but very little here. So they are very short in the way of support, both in the way of transmission and generation.

Then the other issue is for those who have been following the wind energy development, there's significant new wind energy development in the eastern New Mexico area, and proposed new wind generation, then how does that get integrated and how does that get moved to the different markets.

This is a listing of the chairmen of each of these groups, and after we finish they'll have an opportunity to talk about the underlying areas within SWAT. And so Ken from R.W. Beck will talk about the Colorado River transmission system and how it works with STEP and SWAT.

I think what we're going to do next is jump down and let -- Bob Linson is the chair of the Arizona power central Arizona high voltage, Mark Etherton market voltage. Arizona-New Mexico area. Gary Romero will touch on the New Mexico area, then touch on the CATS EHV.

Lastly, Gary is also the coordinator and the chairman for the technical study groups again to ensure we have common base cases, but he will also touch on the CATS Phase III report. Although for planning mode we're always looking forward, and it's sometimes easy to forget that once you get something done you want to get the next report out, that the basis for all of our 10-year filings in January were based upon the study work included in the Phase III report, so Gary will touch on that portion of it before we talk about our 10-year filings later on.

Also you can't do a presentation on SWAT without talking a little bit on the success stories. I won't spend too much time on this, but what you see here in red is from the CATS Phase II report. That was that long-term EHV transmission system that was envisioned. Well, what these bubbles represent is progress made towards implementing that long-term plan. Down here, in the Benson area, southwest transmission has the honor of being the first entity to move forward with one of the CATS projects. And they started construction on the

Winchester substation back last year, and they should be in service right around -- in service, correct -- and it's almost been completed this summer and it's operating. The Winchester substation was sort of this anchor point down here, right now integrates the TEP 345 system and 230, southwest transmission system. But it's been designed and constructed to accommodate 500 expansion to the north, to tie into this overall system.

The next item is what's known as the Palo Verde/Pinal West project. We just talked about siting. We got finished going through a lengthy siting process, but one that was quite efficient, and it resulted in the approval by the Commissioners just last month for two 500 kV transmission lines to be built over a 20-year time frame, with the expected in-service date of the first line in 2006.

The filing in the application relied heavily on the study work by CATS, and it becomes evident when you look here on anything you want to do out of here, ties back to this particular link, it becomes a very key cog in a system, especially when you want access to Palo Verde or from Palo Verde.

So the first line will allow some staged construction to occur, but that second line is in there also because there's a lot of federal lands in Arizona, and if you don't build a transmission line through here, you're not going to build it somewhere else, because you have the Sonoran National Monument right down here, then you have the PNS creeping up on this corridor for 20 years, the request for 20 years, what the ultimate plan is going to be, than coming back in 10 years, making that same application and having the question why didn't you let us know.

The third area is in here, and it's anticipated that SRP working on behalf of APS, Tucson Electric Power, and the Santa Cruz Water and Power District Association, which represents the electrical districts of Pinal County, will be making an application later this year, and there's another announcement later on regarding some of this, but I'm going to allow that to be stated by the entity that's here.

And the time frame here will cover in the 10-year plans. But again, it's to build upon this foundation that has been laid now through four years' worth of development. And as you'll see, especially compared to the very first biennial assessment, you're not going to see dramatic changes in our 10-year filings, I don't believe. I think you're going to see a lot more consistency in the plans that are being put forward versus a lot of dynamics of the changes.

And then in conclusion, why does it work? Well, the idea is openness and collaboration. By involving everybody and resolving issues and incorporating the ideas and needs for those entities up front, we avoid conflicts at the end.

Everyone here is committed to communication, that's why you're here. That's why the panelists are here and will be up here. And having this open environment will hopefully make us allow to move forward with the right decisions in the right directions, and meet the needs of the entire community.

So with that, thank you.

MR. PALERMO: Are there questions for this panel? Before we go to the subgroups, I think it would be appropriate to have questions here, if there were questions.

Please go ahead. State your name.

MR. EISEN: I'll try to do that. It's hard getting it out. I'm Gary Eisen with CAP. I have a question for Mr. Miller on the records test graph that you had where it was really tightly condensed, then it blew out. Is that part wires and part operations? In other words, does that require coordinated operations to get to that place?

MR. MILLER: Yes, it would require coordinated operations. To fully get there, you probably have to do more than build transmission lines. There's other limitations that require California to generate more of its power internally, but by building the transmission, you pave the way for addressing those other concerns and eventually getting to the point where you can efficiently operate the grid.

I'd also like to mention we're not trying to capture the full range of all those points. We're trying to just capture the amount that is economic to capture. In other words, it's not worth building transmission for those last few points say between 9,000 and 10,000 East of River. The economic benefit of enabling the system to do that is probably not worth the cost of building the transmission to do it.

MR. PALERMO: Other questions back here.

MS. WOODALL: Laurie Woodall from the Attorney General's Office. I'd like Mr. Miller, then Mr. Kondziolka to describe the level of participation in STEP and SWAT respectively of either landowner developers and environmental groups.

MR. MILLER: In STEP, when we first started out, that we had our first meeting in November, oh, 2002, we had over 100 people show up at that meeting, and at the first meeting we did have fairly good representation from some environmental groups. We had Greenpeace and Sierra Club, and a few others.

I can't say that they've stayed with us through the whole process. I think it's difficult for them to participate on long-term things like this. I think they're focused more on the short-term. So we haven't seen that participation continue.

MR. KONDZIOLKA: We don't meet in San Diego, and needless to say, the participation of those is not quite as high in SWAT as in STEP.

As far as what you would probably consider a more traditional environmentalist type groups, none are actively participating in SWAT. We do have different environmental planning type groups that do participate in SWAT. Many of them are the types of consultants that might represent utilities or other interests and parties in transmission line siting. Many times they are not actively participating in the meetings, but they are on the, what we call the correspondence list, so they get all the information that's sent out.

With respect to developers, the participation is more of the generation developers, more so than any other particular groups that are there. There have been marketers that have been participating at different stages. That has waned a little bit, but that's been because of this whole consolidation in the industry.

But I think it's important pointing out, from the developers' perspective, there are independent transmission developers participating. The one that comes in mind is Trans-Elec. They have worked with the Dine Power Authority in the proposed Navajo transmission project.

MR. JERRY SMITH: I would like to go back to Gary's question of Jeff. Looking at East of River nomogram, looking at the past operational year, we get the impression from looking at that nomogram that the limitations were not approached to the point you would have curtailments or limitations in schedules, but you mentioned something about actual individual lines might have been posing a problem and causing constraints. Can you give us some perspective of how frequently or often individual elements might pose a constraint as opposed to the path rating?

MR. MILLER: Yes. I think a good example is the situation we have in San Diego right now where there are local limitations from Imperial Valley substation on into Niguel substation is from right, essentially, in San Diego, then downstream in the San Diego system on the 230 kV system. Those constraints, which there are projects underway to address, are so significant that you really can't utilize the existing transmission from Palo Verde into its full extent. But once those are addressed, then the existing lines from Palo Verde would immediately become very heavily congested and would still limit you to well below the full East of River capability in normal operation.

So that's what the STEP upgrades enable us to do, is to operate up to the full 7550. Not only that, but to go beyond that, we think, to around 8,000.

MS. ERIC: Sedina Eric. This question is for Jeff Miller. You mentioned that the STEP study indicated congestion caused 110 to 140 million, and I understood it was for the whole region, WECC. Do you have a bulk number? What are the congestion costs tabulated to congestion to interface between California and Arizona West of River?

MR. MILLER: It's around 60 million.

MS. ERIC: The other question is for Jeff, and for both. Whether these reinforcements which are described in the STEP study and are related for the Devers and Palo Verde lines and the serial capacitors, whether that reinforcement increase or decrease import limits in the Arizona.

A VOICE: What's the question?

MS. ERIC: In the STEP study, there are

several reinforcements that are on the lines between Palo Verde and Devers. It's serial capacitors, additional lines, SVC, I understood. This reinforcement of the system will obviously increase import to California. How this reinforcement will impact import limits to Arizona, whether that will decrease or increase the total import into Arizona.

MR. BOB SMITH: I think practically speaking it won't change anything. We'll treat the capacity increase as bidirectional, but the reality is there aren't enough resources in California with the constraints further north in the northwest to allow imports into Arizona from California anywhere close to what we consider the scheduling capacity, so I don't think it will change anything.

MR. MILLER: There's sort of an interesting twist to this we haven't really discussed here, and that is that really, if you look at these upgrades as well, this is to serve California in the summer. Some of that is the case, but for the higher level upgrades, not necessarily so.

When we look at the economic studies we see Arizona peaks about the same time California does, so the highest stress on the Arizona-California interface is not during the summer peak periods as you might suspect. It's more during the off-peak fall periods, and a lot of the Arizona energy which you're rich with is being sent up to the northwest, the Pacific Northwest, where they're energy limited because they have hydro resources. So you can really see, this is a regional grid, and these reinforcements are not just Arizona and California, they're really for the entire interconnection.

MR. BOB SMITH: Having said that, the increased capacity between Hassayampa and North Gila, APS would be allocated a share of that, and that would increase our scheduling capability to Yuma. That's a pretty small scale compared to the big numbers.

MR. MILLER: The SWAT upgrades, any of those are intended to bring much of the generation from Palo Verde and Hassayampa, not so much the upgrades towards California, but the upgrades from Palo Verde back towards Phoenix.

MR. PALERMO: Last question.

MR. MICHEL: My name is Steve Michel, for Jeff. You had talked about the, I guess the 2013 transmission study with the three different generation scenarios, coal, gas and renewables. My understanding is the coal and the renewables were located near the fuel source, but the gas I think you said was going to be located near the loads. Is there an issue there in terms of you need more gas transmission lines to accommodate that you're building your gas plants and your loads instead of resources? How did you deal with that?

MR. MILLER: We didn't really address the gas supply part of it. That could be pointed to as a weakness in the study. It really wasn't intended to be an overall integrated resource plan. It was just, given the way we thought these resources would develop, here's the transmission requirements. So there are issues in gas supply.

However, in many of the load centers, there are old inefficient gas plants which have half the efficiency of the new plants. So you can put a new plant in and get twice the megawatts out without increasing the demand on the gas system at all. So there's a lot of opportunities there with the existing gas system, just to make better use of it.

MR. PALERMO: Prem, one last question. Since he's a client I'll give an extra question.

MR. BAHL: Prem Bahl. I wasn't disappointed when he said it was the last question.

Jeff, question for you about SSG-WI plans, the shorter plans that the California ISO board has recently approved. There's an excellent article in the electricity utility report of yesterday which give a lot of details about that group process. A total of $150 million have been approved to be spent on these projects, and even at conservative gas price of $4 per million Btu it states that the sort of upgrades will cost $26 million with economic benefits of 62 million. That is very encouraging, and does it lead us to believe that the payback would be on these expenses on the sort of upgrades would be envious because of the benefits, or is there a period of time in which these benefits accrue?

I also would like to know, what is the process for allocating these costs? Is California ISO going to incur the initial expenditures, or other participants or beneficiaries of these projects would also contribute to expenditures?

MR. MILLER: As far as the payback period, I think it could be a year or less. Our studies showed a couple year payback, and that assumes California paid for all of it. I don't think that's the way it's going to end up, but that's the second part of your question. I think it could be a very fast payback, because the studies that we conducted, which came up with that $62 million benefit, were fairly conservative studies. They had a low gas price. They only capture some of the economic benefits. We think that they significantly underestimate the economic benefits.

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Then there's some of other benefits that come with it. One is better utilization of natural gas. We're wasting less natural gas, getting more energy from the gas that we burn, and the new plants are far cleaner than the old plants. So we're doing less harm to the environment. So those are additional benefits that, if we could quantify, I think would show the payback period is much less than as we indicated in our board memo as two and a half years.

On your second question, as far as allocating costs, there will be, I assume, some sharing of the costs with Arizona and with IID, Arizona Public Service, in particular. They own a piece of the project. They have a choice about whether or not they participate, as does the Imperial Irrigation District. Both have indicated informally that they have interest in participating, so I would be surprised if they were not to. If they were not to, then I think we might step forward and look for the whole chunk of capacity. Those that participate get the additional allocations and so on, so forth. So there's definitely advantages there to participate.

The costs that are borne by California ISO ratepayers will be spread across the entire ISO grid. The axis charge structure that we have says anything 200 kV and above is spread across all the ratepayers in the grid, so the one in California, southern California, and San Diego will all pay the same increase based upon this additional expenditure.

MR. BAHL: You mentioned --

MR. PALERMO: I know you're the client, but that's it.

MR. BAHL: Okay.

MR. PALERMO: I always have my whip, but I do want to keep us on schedule.

I want to thank this panel. We still have the SWAT subcommittees to hear from, and we want to at least start on the Commission's response to the RMR study this morning. So with that in mind, I propose that we only take a 10-minute break now. And that means that you can get water, and only those of you that are desperate can get coffee, because you can't bring food or drink back into the auditorium. So in 10 minutes there's not a lot of time to do that.

(A recess ensued.)

MR. PALERMO: I would like to say two things briefly before we start this panel. First is that all of the materials that are being presented will be posted on the website of the Commission, so if you're desperate to get some of it, you don't need to collar somebody and ask them for that material. It all will be posted on the website in the next day or two.

The second is I want to offer an apology to this group, and also let you know something that I've asked them to emphasize the Phase III material as opposed to everything else that they are doing. So I mean no slight to any of the subcommittees that we're going to spend more time on that, but due to the amount of time we have I'd like to allow more time for that.

So again, I ask each of you to introduce yourselves at the beginning, and your company, then we'll proceed right now.

MR. ROMERO: My name is Gary Romero from the transmission planning department within Salt River Project.

MR. BAGLEY: Ken Bagley with R.W. Beck.

MR. ETHERTON: Mark Etherton from K.R. Saline Associates.

MR. BAGLEY: My presentation today will discuss the concerns, activities, membership of the combined SWAT, CRT and STEP AC committees. A lot of what I will say has already been discussed, but from a review perspective, I understand the pop quiz at the end of this meeting counts for about 20 percent of your grade towards compliance with the PTA.

Anyway, it has been discussed, the reason of the combined committees deals with the area between Phoenix, Las Vegas, Los Angeles, San Diego, down to Yuma. What we have within that area is at one point where three different planning committees were involved, WATS, STEP, as well as SWAT.

WATS, western Arizona transmission system, has been in existence for a number of years. Its membership consists of entities who have ownership in what are called the East of River or Path 49 facilities. Membership in that committee is limited basically to owners of the facilities, although some of their meetings are open to the public. There are other meetings they have that are closed to just the membership.

The SWAT, CRT, it was created as the subregion to the SWAT planning group. Its intent basically is to look at the needs or transmission and the current status of the transmission systems within western Arizona and southern Nevada. Membership, as with SWAT, is completely open.

STEP-AC, a little expanded history from what was discussed before. When STEP first initiated, they basically took suggestions on a number of different transmission projects, at one point had over 20 that were being given consideration. These were eventually narrowed down to a much shorter list, but it was evident that at least one project would be some kind of an EHV line between Arizona and California. One explicit project that has been discussed is Southern Cal Edison's proposed Devers 2 facility. The purpose of the Arizona AC was to look at, the Arizona-California committee, to actually look at what options made sense for the region. So that's why that group was created.

By combining these two groups, what we've done again is minimize the overlap of the two planning subcommittees. And because again the number, if not almost all of the membership of the two committees were the same, it would just allow us to meet at one time to discuss the issues that were common to both and to pursue in planning for both those entities.

Participants in the combined committee are the transmission owners, load-serving entities, regulatory commission, developers, again, we haven't had environmental type people showing up, but developers from the perspective of the transmission or the IPPs and transmission, merchant transmission within Arizona -- and I apologize if I have missed anyone -- 12 different entities who have been participating in monitoring our meetings today. Within California, six; Nevada, one. Nevada Power, others, Trans-Elec, as well as Western Wind Development.

We've got about 21, 22 entities that are actually participating or monitoring the CRT-AC meetings and activities. Again, just to show the area of our studies are concerned. What I've got here is actually showing the EHV lines, comprise of the East of River Path 49 facilities. The East of River system that overrides our study area, the main reason to transfer the power from the generation sources in Phoenix into southern Nevada for transport down into southern California. Within that region we have several planned upgrades or expansions of transmission. Series cap upgrades, as Jeff Miller discussed, Palo Verde/Devers 2, East of River, 9,000. Also as was mentioned, the Navajo transmission project which, from our perspective, would be the segment going from Moenkopi into Marketplace. The consideration is tying into that project just north of Kingman and trying to serve northwestern Arizona, then Desert Southwest Transmission, which is a group that represents the Blythe area generation, is looking in to get that generation out of the Blythe, California area into Devers.

We also have the underlying HV system which I've shown here in blue. That entire system I've shown here is actually owned by the Western Area Power Administration, but much of the load that actually exists in western Arizona is served off of this transmission system, not off of the EHV.

Upgrades again planned for the EHV system in our region is by Unisource, which is a parent to Tucson Electric. A 230 tie from Griffith to North Havasu. Western Area Power Administration is looking to attempt to reconductor one of their 230 lines from Topock to Mead, as well as trying to do a structure replacement on now the 161 lines heading south out of Parker to Blythe on down to Yuma. They won't actually be upgrading the conductor of the 230 right now, but are looking to install 230 capable structures.

What I'm showing here are where the actual load pockets are within western Arizona that are a concern to our group. I've shown two different colors. The blue circles are loads associated to more residential/commercial type activities that are growing. The red circles represent loads of the Central Arizona Project which are substantial, but are not expected to grow at least during the next 10 to 12 years.

I apologize if you haven't read this one. This here is an effort to actually show what kind of loads do we actually have in the region now. It would show APS, Yuma area at 344, growing by 2012 to 2425. CAP has approximately 420 megawatts in those three red bubbles I showed before. Those are pumping loads related to irrigation in the Central Arizona Project.

Mohave Electric Cooperative. These are not numbers from Mohave, based on the information I've been given in about 141 megawatts now with the potential of maybe doubling over the next five to ten years.

Then we have Unisource who recently acquired Citizens' operations in northwestern Arizona with their loads in both Kingman and Lake Havasu, which again, as you can see, a percentage growth wise, expecting some significant growth in that area.

What I'm now showing, then, is the location of the generation within that region. We have two types of generation in that area. We have three independent power producers: Duke's Griffith plant, Calpine South Point, Florida Power Light's energy facilities, as well as two hydro facilities, Davis and Parker Dam. There will be more later. The generation in this area actually exceeds load presently, at least.

Issues for the LSEs within our study group area is again the fact they are experiencing some meaningful load growth. The fact that the system, again which is owned principally by Western Area Power Administration is not thermally but contractually constrained. Western has committed that transmission to various entities, a number of which are not serving load in that area but attempting to pass through that area, which includes a number of the IPPs. Again, the fact that the LSEs actually don't have control of that generation, so although it is an actual export area when all generation is on, the IPPs do not have a commitment to serve the local loads and therefore the LSEs can't count on that generation being on line in helping support voltage in the entire northwestern area.

What we are doing as a study group right now is a two-phase approach. We have a technical subcommittee that's going on within the CRT. Right now, the two study efforts in that group is to, one, look at stressing the existing East of River path to see what we can do to increase transmission, if you will, up into northwestern Arizona and southern Nevada with the existing facilities.

Secondly, Tucson Electric Power is heading up a study to look at a new circuit which will actually tie into what is being called the APS TS-5 project, head over to the Lake Havasu area where they are experiencing a significant load growth, connected up to Mohave, which would direct it to East of River into southern California.

We also are attempting to coordinate various projects being proposed that will increase capacities. Devers/Palo Verde, East of River 9,000 and again the APS TS-5 project.

I want to say to those with regards to the STEP side of this thing, my presentation has been pretty much oriented around what's going on in Arizona because of it being associated as BTA, but again, we are very much concerned with the needs and concerns of the California and southern Nevada participants of this group as well.

With that, just kind of concluding slide. What this diagram is attempting to do is actually show the extent of interests of the entities who are participants in both the CRT and AC committees. What these lines are attempting to do is not show actual proposed transmission paths, but actually the magnitude and interest of transmission represented by the various entities.

As you can see again, Nevada Power, with 250 heading up to southern Nevada, Southwestern Transmission Co-op trying to help Mohave Electric. Tucson Electric, Unisource to serve southern Arizona, Kingman. Central Arizona Project, trying to have its internal supply, pumping loads, Southern Cal is 1200 megawatts. IID with 200 megawatts. Florida Power & Light to Blythe. Desert Southwest Transmission, their interest is actually getting from the Blythe area, where there's currently one 520 megawatt unit. The second proposed 520 megawatt from Blythe into Devers.

So the interest is substantial for additional transmission capacity. We could easily justify several EHV circuits to address all these needs, but again, for some of these entities there are no EHV facilities in the region of their load-serving obligations. That ends my presentation.

MR. ETHERTON: My name is Mark Etherton from K.R. Saline Associates. I'll talk a little bit about on the eastern side of the Arizona boundary we have another SWAT group that's called the SWAT Arizona-New Mexico specific study area. I think I'll jump to that one real quick.

Again, I think what I'd like to emphasize here, being chairman is one title, but I also think being a volunteer to help kind of lead some of these committees is probably a favorite challenge, because it's tough to get people to actually step up and do this. Rob owes me a couple lunches and everything else. We really only had one major meeting that we've got everybody together and kind of talked about what all the interests are, and what's been going on in the Four Corners of the Arizona-New Mexico area. Bob Smith actually recommended that our first meeting be held as a joint Four Corners area task force, which has been in existence for 20, 20 some years, and invite some of the SWAT members across the region as well, and all the independents and everybody else.

First meeting, about 27 people attended. We had a pretty good turnout. APS helped host it for us. Quite a few generation project presentations, three actually coal projects, delivering about 2400 megawatts in the region, one wind project, about 100 megawatts. We had a handful of transmission project presentations also with the NTP, the 500 line out of the Four Corners area. PNM is actually looking at a new 345 for the area out into Albuquerque. Western gave us a presentation on the update of the 345 triangle between Shiprock, Four Corners, and San Juan up in that area as well.

We also spent quite a bit of time going through what really everybody is interested in in this region. We're trying to take the approach in this task force to look out as far as we can, 10 plus years, considering that anything that's going to have to be done necessarily is going to have to be new transmission, and its significant time frame, we'll get some of those areas planned.

As you can see by this list, I'm not going to go through it all in detail for the court reporter to keep up with me. There's significant interest in these areas. Some of these overlap between generation loads and some of the load of the people need it on the other end. I actually put a map together to kind of represent this.

The red circles represent more of the bulk of where the generation will be or is today. And the yellow transmission paths with the numbers above them kind of indicate where the actual transmission needs are, and which direction they actually are. Some of them, again, you can see there's some alignment between different areas, but there's significant needs across this area, especially in the Four Corners area, that seems to be the hottest area right now with the typical activity.

We put together a graphed study plan that was basically approved last month, developed a long-term Arizona-New Mexico system. We tried to align a lot of the common interest projects across this region to meet those needs. We're working on putting a base case together right now. We're starting with the one that the CATS effort is putting together from the 2012 time frame, and we'll expand on that to put all these projects in there and have different people look at different projects. The interested parties we studied in particular, common interest projects and hopefully toward the end of November time frame or so, we'll bring our results together for one technical review and comments and incorporate it in a single report.

I'll kind of go through the time line real quick. Finalize the study plan. Hopefully in July we'll finalize the base case with all the projects and all the needs, come up with some preliminary findings sometime in October, and the draft report in November, and wrap it all together with all the SWAT reports in December and one common area. That's all I had on that one.

The other one is, there will be a lot more detail, I think I'm going to try to go through a little fast because I think Gary is going to talk a little more about the CATS Phase III effort. This is a small subgroup of CATS, called the CATS HV. After about the first year, I would say, of going through all the CATS, I don't know what happened to this area in the upper right-hand corner. The Arizona Corporation Commission. It didn't say that on the original slide.

MR. BAGLEY: What it says is what the bleep do we know.

MR. ETHERTON: It's a collaborative effort from this area, to look at the underlying 230 system as a 500 system that you saw the big map that Rob presented was being overlaid on top of this. There's significant potential for growth in this area, and overlaying the 500 system on top of that.

There was a concern that the 115 which serves that area primarily was going to be overloaded, not keep up, so this group was kind of formed to kind of start looking at some of that. Actually, Bob Linson and Steve Mendoza started the group, and Bob and I kind of co-chair the Arizona power authorities.

Again, I talked a little bit about the background. We're really trying to get to how we approached it in the last couple years, what are the limitations of the existing system, what are the 10-year system requirements, what's going to happen if we overlay 500 kV on top of this area and maybe not have offramps.

Since the last BTA two years ago we kind of started this effort. We had our first report published October, 2003, and that was -- I'm going to go into a little bit more detail on that. The second one is kind of in draft right now. Western desert southwest is leading, and we've got a draft out right now for review, and hopefully we'll finalize that in the next month or two.

2003 analysis really again focused on what the heck the existing issues are on the system, reviews, possible 115 upgrades to 230. It reviews some of the offramps I talked about to the 500 kV system, and really one of the main focus, try to come up with a recommendation that the CATS Phase III EHV study would look at what they're looking at for the area. Phase study, kind of looking in different phases, what was planned to get built out in the next five to ten years with the existing system.

Phase I was upgrade, Western was going to south of Phoenix project. 230 kV interconnections again to the proposed Palo Verde/Southeast Valley line. Some improvements for the Coolidge/Rogers area that were known to be bottlenecks in the region. Some other longer term upgrades. We're looking at south of Coolidge basically.

One of the findings that we found from the system, I'm going to go through these again real briefly, the existing system was found to be adequate to serve the expected 2006 load. No real surprise there. But as the load continued to increase, the way we did that, just put block loads at a couple different substations around the area. About when the load doubles to what we call the 2006 level, we started seeing some problems in the Coolidge central ED-2 from the 115 lines serving the area from the bulk receiving stations down into the load.

Again, for 2006 we didn't really see any major RMR. There's two generators located in the area, Desert Basin and Sundance. We had a quick snapshot of those just to see if there are issues. South Phoenix project, which hopefully will be in service by next summer, will provide additional voltage support, additional transmission capacity as load continues to grow in the area.

We also looked at a little tie between the Western and APS ties down at Casa Grande. When Casa Grande and Western gets up to the 230, we looked at putting a little tie there together as today they're not, they share a common fence, to kind of look into relieving some of the area, Casa Grande loading issues for loss of line out of Desert Basin up to the Santa Rosa area.

We also looked at ties to the Santa Rosa and Coolidge 230 substations I guess for the Palo Verde/Southeast Valley, and we thought maybe having a parallel 230 system along with the 500 that if you lost the 500 you'd see some overloads, and we did not see overloads.

Some of the recommendations that we came out with included all the projects through what we called Phase III into the CATS main for Phase III EHV study effort. We'll take some time this year and probably through the rest of the year as well to look at additional 115 to 230 upgrades to provide for kind of subtransmission system to serve the load. Right now the 115 is being used as subtransmission, and as some of this gets upgraded to 230, more than likely we'll start switching to 230 for high voltage and 69 for subtransmission to serve the area.

From that, Western Area Power Administration had taken some of the initial stuff that we had said okay, let's take a look at a little bit more detail now on the actual, when the first phase of the South Phoenix project gets upgraded, what is the actual rating, the cut plane rating in the area, what it's going to do, start looking at some of the best possible expansion project for what they call the southern Arizona upgrades as well, and keep continuing the findings from our 2003 studies, last year, to know base case, what we call the Phase I with south of Phoenix upgrades. That's listing what the south of Phoenix upgrades were. Most of those are 115 today and constructed 230. They'll be entered as of 230 by next June, 2005.

Part of the study plan also was adjust the load to 2003 actual load level to last summer peak I think is what Western used as their base, 475 megawatts for the area, 525 for maximum load generation conditions in Arizona. Start growing that system area loads at the same rate and power factor to determine limiting elements under different varying conditions, thermal and both of the issues we looked at that.

Generation was discussed and the load was growing, only supplied by Palo Verde hub generation along with using the line, the 500 line in the region, and examined sensitivity of southern Arizona load-serving capabilities with respect to different power factors.

That's one of the sensitivities that's being completed.

Some of the early findings that Western is producing is that the area is basically capable of serving about 940 megawatts of load, about an 80 percent increase of where it's at today under the maximum load serving generation conditions as well, and with zero generation somewhere around 740 megawatts, about a 60 percent increase from today.

Some of the limiting factors, limiting elements that Westerners found is Coolidge 230 to 15 transformer, one of the power lines not being upgraded. Saguaro to Oracle line also found to be overloaded in some in-line conditions. That is finding voltage issues. They could either be delta V or different in 5 percent, or actual load voltage in different conditions.

Naturally, as the load grows, typically capacitor requirements will also keep up with that as well. I guess that's where that finding is coming from. With zero generation at Desert Basin and Sundance there's a couple other stations that had even higher voltage deviations at 85, and a substation called Red Rock, lower additional load, 25 percent increase from today.

The next step where we're headed for the rest of this year, finalize the study report that Western is working on now. We asked them to do a couple more sensitivities, as well to have that wrapped up, at least presented at the next SWAT major meeting in August. We're still trying to finalize the 10-year plan which we're going to call 2019. It also includes all the transmission upgrades, and voltage support requirements expected to meet the 2014 loads.

Expand on the long-term requirements beyond that 10 years, we've got a little brief saturated load level for the area. We're starting expanding on that. Some of these other requirements come up over the next two years.

With that, that concludes my portion.

MR. ROMERO: My name is Gary Romero. I'm the chairman of the SWAT, CATS EHV subcommittee, and also the chairman of the SWAT technical oversight committee. Dave Eubank from PNM was not able to attend today, so I'll be giving a very brief update of where the New Mexico subgroup is. I'll give another brief update on where the CATS EHV subgroup is today, and I'll spend a lot more time on the CATS Phase III report.

So to begin, Rob touched a lot on where the New Mexico subgroup is right now. Basically, this is a section of the overview that he showed with just the New Mexico area highlighted in the center there in brown. He touched on the transmission issues that they're facing today. Mainly what they want to look at is moving resources from the Four Corners area into the load centers, and moving resources from the eastern side of New Mexico, mainly the wind farms, into their load centers, and to relieve the congestion they have in south Texas, El Paso area.

Resource assumptions they're looking at. They want to make sure they look at all existing and planned resources for the 2012 time frame. They're also going to look at announced new resources in eastern Arizona and New Mexico region, mainly the Four Corners area, and future wind resources in eastern New Mexico.

Transmission. They're going to make sure they model all of their planned transmission plus all alternatives that they have identified so far. Currently what they're doing, they are in the process of developing their study plan, and that's where they are today.

I'll go on to my next presentation. CATS, SWAT, CATS EHV study area. Basically what you see here is a map of Arizona with the existing EHV transmission shown in white, planned transmission shown in red, and the basic study area shown in green. And it looks like green on the screen, too.

Basically, the area that the central Arizona looks at is going to be from the Palo Verde side, Palo

Verde hub to the eastern Arizona border, and south to south of Tucson, up to the northern edge of the Phoenix area. This subcommittee is going to have some overlap with East of River subcommittee, Colorado River subcommittee Ken Raga's group. There will be several overlap in New Mexico and southern, mainly on the eastern edge of the state. The CATS EHV subcommittee group will be looking at transmission issues on the 500 kV level mainly and Arizona-New Mexico subgroup will look at the lower voltages in that area. That's where the overlap is going to take place.

Study purpose. Mainly to review transmission options to improve import capability into the Phoenix and Tucson area, review scheduling options from resources in eastern Arizona, New Mexico into central Arizona, and also review scheduling options from resources in eastern Arizona, New Mexico region through Arizona, into southern California.

Base case development. Basically we're starting from a WECC 2012, summer base case which was approved in 2003. It was also the same case used for the Arizona 2012 RMR study. 2008 RMR case will be used to study the Palo Verde to TS-5 project. Sensitivity work will be done on the WATS 8055 case which has recently been approved by the WATS group.

Resource assumptions. All existing planned resources for the 2012 time frame will be looked at. All announced new resources in eastern Arizona, New Mexico region will also be looked at.

Transmission assumptions. All existing and planned transmission for the 2012 time frame will be modeled in an initial base case, and the major planned EHV you see there in red is, basically, we'll be looking at the Pinal West or the Palo Verde/Pinal West transmission line, Pinal West into Santa Rosa and Santa Rosa into the Browning station in the eastern Phoenix area.

To the north, we will be mulling the Palo Verde TS-5 project, and TS-5 up to Raceway, and at Raceway there will be a loop-in of one of the Navajo to Western lines into lines, that will be the initial base case that will be built.

Transmission alternatives. The alternatives we're going to be looking at are alternatives to improve import capability into Phoenix and Tucson. Alternatives that will schedule resources from Arizona, New Mexico, into Phoenix and Tucson, then possibly a combination of the above to schedule resources from Arizona, New Mexico, through central Arizona into southern California.

On this slide we show, and it looks like the brown on the screen, is the study alternatives that we have identified so far. Mainly, the alternatives are going to be from the Four Corners area into Cholla down into north Phoenix area, the Pinnacle Peak station. From there we'll be looking at several alternatives, 500 kV lines from Pinnacle Peak into central Phoenix. We're also looking at a possible Raceway alternative into the Pinnacle Peak area. More alternatives from the Palo Verde hub into Phoenix and from the Palo Verde hub down into Tucson.

On the eastern side of the state we're going to be looking at alternatives from the Pinal South/Southeast Valley station into the Tucson area also.

Study time line. This looks very similar to what Mark had up there except for the finalized study plan. We're looking at having it finalized at the end of this month or within the next couple weeks. Basically we're still looking at finalized, looking at July, preliminary results in September. Draft report out in November, for the final report out in December. That concludes that one.

Now we'll get into the CATS Phase III study. Introduction. Rob touched on the CATS Phase I and Phase II studies. Basically they were collaborative regional transmission studies mainly to develop a high level transmission plan for central Arizona, with the objective to maximize regional benefits while developing the plan that makes more efficient use of existing transmission system.

Basically, these were collaborative, comparative analysis of transmission system. They do not represent any time frame, any specific time frame. Whereas the CATS Phase III study is more of a regional transmission collaborative effort to develop a 10-year regional transmission plan for central Arizona.

The study work participants consisted of Arizona Public Service, Salt River Project, Southwest Transmission Cooperative, Tucson Electric Power, and Western Area Power Administration.

The main objectives of the CATS Phase III study were to perform a 10-year regional transmission assessment for central Arizona, at the same time develop a joint 2012 joint case for central Arizona. With this, to assess the impact of individual transmission plans on the overall transmission system for central Arizona, and to provide a common foundation for filing 10-year plans.

This map shows the basic study area highlighted in light blue or violet on the screen. It's basically the same study area as before, mainly Palo Verde, looking from Palo Verde to the eastern edge of Arizona, and the north edge of Phoenix, down into the south edge of Tucson.

The EHV that was studied and modeled in this plan was, it's highlighted in green there. Basically, it was a 500 kV line from the Palo Verde hub area into Pinal West, and then from Pinal West into the Phoenix east valley, to a station called Southeast Valley, which would then be looped into a Coronado serving line. From Pinal West we also looked at a line to Saguaro substation, from Saguaro down into south of Tucson on the bottom.

Methodology used. We started with a base case selection. The case that was selected was a 2006 heavy summer case, wet case. From that we updated that case to 2012 time frame with everybody's planned facilities in the case.

We broke up into three separate areas, Phoenix area, southern Arizona, and central Arizona, and the study participants each ran separate N-0 and N-1 studies on that base case. From that, they identified any problems that may have popped up, overload problems, thermal problems, and applied fixes to them. And once they applied fixes, we then got together, analyzed all that we found, and how we fixed it, and we inputted that into the case again and reran that base case for N-1 and N-0 with all new fixes, and at the end came up with a refined long range transmission plan. That was the plan methodology.

With the conclusions you'll find out what actually happened. The first conclusion is that running the N-0 and N-1 problems, we had no EHV problems in the area. We ran fixes, didn't find any problems. Everyone's planned facilities were a charm; they did their job good. Individual 10-year plans had no negative effects on the overall system when studied together for N-0 and N-1.

There were some problems identified on the underlying systems, mainly the 230 system and below. These problems would be addressed in the individual short-term planning arenas. A lot of these problems were based on the EHV study was a bulk study, the only model down to the 230 system. When you look at these problems on a detailed case where you have underlying 69 system there, most of these problems disappear; in fact, almost all of them disappear, with some exceptions.

Recommendations. Future studies can be, should be coordinated to what is now called the SWAT, such that every two years a 10-year study is performed to coincide with the ACC biennial transmission assessment. The study process should encompass a coordinated base case for joint planning studies. SWAT should also be included as the forum to coordinate regional transmission studies and to fulfill state and regulatory needs.

That's all I have.

MR. PALERMO: Thank you. We will take just a few questions, which I figure is more than a couple, and less than, so it's three questions.

MR. WILLIAMSON: Ray Williamson. Question for Mr. Romero. Two, three years ago Public Service of New Mexico was proposing a line from Palo Verde down through Nogales possibly crossing into New Mexico. I haven't heard anything about it lately. Is it still being actively considered, or are they withdrawing that as a proposed project?

MR. ROMERO: We no longer intended to have that project as one of the alternatives. It was looked at in CATS Phase I and Phase II, but we haven't heard any more about it at all.

MR. WILLIAMSON: Thank you.

MS. ERIC: Sedina Eric. All of the panelists mentioned something which is related to generation resources and assumptions in the planning data.

You mentioned, with respect to one table, some numbers. Well, the table showed the numbers of the utilities and the numbers of megawatts, and I understood it's a new generation at Four Corners and somewhere else. Am I right, or is the combination of new and old? After that it was a slide showing the need to the, different areas from the region at Four Corners.

MR. ETHERTON: Maybe I could address that. The way we developed that chart was actually based on transmission needs. So those numbers are transmission needs. Those may relate to future resource requirements, but those were the actual transmission capacity requirements that everybody was looking for in that area. Some of those folks were load-serving entities, some of those folks were independent power producers looking for transmission to get their resources to a load center.

MS. ERIC: Related to new IPPs, you mentioned that you put in your base cases all the generators that announced. What did you mean by that? Is it generators that applied or generation for connection queue or have an interconnection agreement executed or just studies? What is the level of legitimacy of that announcement?

MR. ROMERO: The first bullet mentioned planned facilities. These are generators that are in the queue that are in the process of being constructed or will soon be constructed. The announced are the ones, that's all they are, is just announced generation. Somebody has said that we plan on applying for a certificate here to build the station, and we're just -- use those for sensitivity, mainly.

MS. ERIC: So some of them might not be even in the queue, or all of them are in generation?

MR. ROMERO: Most all of those will be in the queue.

MR. ETHERTON: But again, some may not be. Some may want to see how their project may fit into an existing transmission system or other plans that are coming out. This is one of the best approaches for this collaborative effort, is to see how you fit in to what's going on and how you could fit your project into the plans. It's kind of a two-way street.

MR. PALERMO: As I recall, this is all 10 years and further into the future, wasn't it?

MR. ETHERTON: Right.

MR. PALERMO: So it's still pretty speculative.

Question in the back.

MR. MICHEL: Steve Michel. You're talking about 10 years there's going to be a lot of changes between now and the time they're putting these plans into place, changes in technology, composite wise, changes where these resources are located. How do you integrate that, what you're doing, to stay flexible enough to accommodate these things without getting locked down the path that ignores new technology that may point you into a different direction?

MR. ETHERTON: The way we see that, it's

direction. The purpose of doing these long-term 10-year plans is to pull everyone's needs together and see what the direction really could be. If we find that a thousand megawatts is better served by replacing conductor and doing some of the composite things, that works out great.

But a lot of it is based on the timing of when some of the new transmission facilities really can feasibly be built. It takes, I've seen numbers anywhere from five to eight years by the time you start planning a transmission line to where it actually gets in service. If you don't do the 10-year plans, it's hard to get some of those out there to get them rolling.

You're right, in the last two years a lot of things have changed. By doing these 10-year plans at least every two years, hopefully they're keeping up to date and you're able to adjust and be flexible during that time frame.

MR. PALERMO: One of the goals of those kinds of really long-term plans is to have an idea what you might do if something happened. You don't actually expect it to happen, but you learn, and like you just said, two years from now what they think will happen 10 years later will probably be very different. But you're still learning each time you do it, depending what really comes along and what people really commit to, what options you have and how they might fit in the long-term plan.

I'd like to thank all three of you for your presentation. To all of you, we are going to start now the next section, which is the response of the Commission Staff to the RMR study that was released early this year. It's my intention, since my body does not have any idea what time zone it's in, that we will go for about an hour and see where we are and stop.

MR. JERRY SMITH: I'm going to cut it very short.

MR. PALERMO: When he's done -- give him an incentive -- we will break for lunch. So maybe 45 minutes or so. Okay?

MR. JERRY SMITH: Since my material is going to be posted on the Corporation Commission website, I'm going to take some liberty today and cut considerably short discussion of the 40 slides that I prepared, and given the fact that over the last two years we've had a workshop of the 2003 RMR study work, and also we had one this year for the 2004.

I think many of you maybe have sat through some of those workshops and I don't want to be redundant and rehash the work that has already been presented. But I think I will try to capture some key points from these 40 slides, and maybe we can get out of here in half an hour for lunch.

I've organized this presentation around five different topics. First of all, these slides try to pull together, out of the 2002 biennial transmission assessment, where we gave definition of what reliability must run generation really is defined to be, at least in Arizona and through our biennial transmission assessment process.

Since that is well documented in the BTA report, and we have reviewed that several times, I'm going to skip over that. But it's at least captured here in this material for the website.

Secondly, we have a procedural framework that has been set in place by the Arizona Corporation Commission for the 2003 and 2004 RMR study effort. I am going to spend a little bit of time reviewing that with you because it gives some context of why we're doing what we're doing and where it's leading us.

Thirdly, I was going to spend some significant time talking about the results. I think I'm going to cut very short my comments on the results, but I will pick a couple of samples to highlight for you some new features that came out of the 2004 effort that I think are worth mentioning. And in particular in this area, I will spend a little bit of time talking about the TEP RMR studies for

Santa Cruz County, which was not available at the time we had our workshop in February.

Then I'll provide some conclusions and reflections on what the industry comments have been as we've gone through those two workshops. And of course, the final slide that you're all waiting to see, what is Staff's recommendation of what we do about RMR study work in the future.

As you know, in the 2002 biennial transmission assessment, it identified there were five geographic areas that were transmission import constrained, and those geographic areas are shown in blue on the slide on the screen. Those are the Yuma area, the Phoenix area, Tucson area, the Santa Cruz County, and also the Mohave County areas.

As I said, I'm not going to go back through and redefine what RMR is in the terms that we've been using, like system import limit, maximum load-serving capability, but I would like to give some reflection here in terms of what we have been trying to get out of these studies is the number of hours which the load is above the transmission import capability, that's the system import limit, and the amount of energy that's involved, which we're calling the RMR energy, and what the maximum RMR load-serving requirement is, which is that amount of capacity that the local generators would be required to produce.

In looking at the procedural framework for the 2003 and 2004 RMR study effort, the source -- the original source of how this was shaped was through Decision No. 65154, which came from the Commission in response to its generic restructuring retail competition Track A proceedings. And in that order, there was the requirement that by January of 2003, we have some RMR studies filed by APS and Tucson Electric Power with the cooperation of the industry that would look at the 2003 through 2005 time period. And then by January of 2004, they would complete their study efforts to continue looking out for the 10-year period. Both of those study efforts were then to be fed into this biennial transmission assessment, and that's why we have this topic on the agenda for today.

But I need to remind you why those study efforts were split into two pieces. We had something going on back in 2002 and 2003 that resulted in a competitive solicitation for APS and Tucson Electric Power for some generation requirements. And those were what were referred to as Track B proceedings. And in a decision that came out of Track B proceedings, it was required that the results of the 2003, 2005 RMR studies should be reflected in the contestable load requirements that those two utilities would be required to bid in their competitive solicitation. So that's why there was a short up-front lead time for some quick information. And I have to say the industry responded very effectively in getting that information in a very short period of time, and I'm very appreciative of that.

But we also learned some things in that first round of RMR studies that led us to do this year's RMR study effort a little differently.

This sort of captures, in one slide, the distinctions between the 2003 and the 2004 studies that have been done for RMR. First up is the obvious difference in the time frame for the studies, which I've already mentioned.

But secondly, and probably as important as anything, is the difference in terms of the study forum. The 2003 effort was one in which the transmission providers worked collectively to quickly pull some studies together to respond to the Track B proceeding needs. There was not an opportunity to make it as collaborative of a process as all of us would have liked, and in fact, we got numerous comments about the deficiencies of it being a closed process. And therefore, for the 2004 RMR studies, the study forum was moved to B-1 under CATS, and it was very collaborative in nature. The workshops that we had for these two study efforts was February of last year, was for the 2003 RMR study, and in January of this year we had the workshop for the 2004.

The flashing address at the bottom of the screen is the location on our website that the Commission, where you can find the reports and presentations that came out of both of those study efforts, and that would be the location of where we will eventually put the slides that I'm presenting you today because much of the information has been pulled from those documents.

Just a quick word about the Yuma area. I think what we have seen as a result of modeling the Yuma area in these two study efforts is some realization that in the midst of all this, we had a new power plant siting approval that's shown in green here as the Wellton-Mohawk power plant that connects into the North Gila 69 kV switchyard of APS, and into the Western Area Power Administration Gila substation. And that was not modeled in the 2003 studies, but was modeled in the 2004 studies.

Also, APS modeled in the 2004 studies their new 230 kV transmission line, which is shown in blue at the bottom right of this particular slide, which comes from Gila Bend to a station called TS-8. And that was a study, I believe, from 2012, whereas the Wellton-Mohawk was represented in the 2008 study time period.

Study results for the Yuma area was pretty consistent between the 2003 and 2004 study effort. What we saw was that there were some significant hours of RMR exposure, to the point that APS found it was warranted advancing a transformer at the North Gila switchyard to 2005, and the cost of construction to relieve the constraint was three and a half million dollars for that transformer. When you look at the 1.5 million per year cost of running RMR generation, it was felt that that was a prudent thing to do, and in doing so, they could reduce the PM-10 emissions by 1.8 tons per year.

Now, you may say what's the real significance of this action. Well, I think we had an event within the last couple of months where we actually had an RMR condition in Yuma. They had an outage, and the generators were not able to respond quickly enough or were not able to get some of the generators on line quick enough, so they had to drop some load in the Yuma area.

That's an example of why RMR studies are important to the Commission. We want to know what the exposure is to consumers. This was an area that we knew was on the margin of needing some corrective action. APS managed the situation just fine, but it's an example of why we need to be cautious of not just assuming local generation is going to always be there and be able to be a solution.

Looking at the 2004 study time period, the cost of mitigating RMR is a little less, and the addition of the Wellton-Mohawk generating plant and the APS line, Gila Bend, are effective in helping mitigate the exposure to RMR conditions.

In the Tucson TEP service area, what has been modeled there is improvements of the Winchester interconnection in 2004, the Copper Valley transmission line from Greenlee, a 345 kV line in 2004. A Gateway substation down to the Nogales area was modeled for 2005. That facility is not under construction, and still going through some federal siting concerns with the environmental impact statement. And they modeled some internal 138 kV upgrades in 2005. And then when you look at 2008, TEP modeled the Palo Verde/Pinal West new line that you heard earlier today from Rob Kondziolka, has been through the siting process and is to be in service by 2006. Additional 138 kV upgrades, and then for 2012, TEP modeled an addition of the line from Pinal West to Tortolita, which is one of the three key entry points into the TEP service area. And in addition, the Tortolita to South 345 kV line addition.

With all of these facilities modeled as I've just described, here is a summary of TEP's RMR study results. You can see that the time period ranges from 2005 through 2012, with the system import limit growing from 1609 in 2005, dropping in 2008 because the growth has occurred but they have not added a lot of facilities in 2008. But by 2008 they've added quite a bit of transmission, therefore the system import limit has grown significantly to 1886.

The RMR energy hours, megawatt hours, you can see sort of reflect what's required as a result of the load growth that occurs in that time period with the RMR energy going from 348 in 2005 up to 826 megawatt hours in 2008, and then dropping off as they add additional transmission facilities in the Tucson area.

At the bottom of this chart are the incremental operating costs for those RMR units. The RMR energy amounts that are shown here for TEP are not large numbers, and therefore you're seeing fairly modest RMR cost increases for RMR generation.

TEP also was effective in presenting the environmental impacts for that same time period, and this captures for the SO_2, NO_x, PM-10, and CO emissions what the RMR generation would produce in the way of those emission categories for the three years that were studied.

Now I want to talk a little bit about Santa Cruz County, because this is one that was not available at the time we had the 2004 RMR workshop.

This material comes from an exhibit that's in the docket that's active right now at the Commission, where we are looking at the request for a waiver for penalties for the second transmission line to Nogales not being yet constructed.

TEP did complete some RMR study work for Unisource Energy Services relative to the Santa Cruz County area, and what this captures is the local peak load for the Santa Cruz County going from 63.6 megawatts in 2005 to 79.2 megawatts in 2012. The system import limit is 50 megawatts until 2012, at which time their studies assumed there were two gateways. The Valencia 115 kV lines and the RMR peak load demands are 13 and 20 megawatts in the first two study years, and there is no RMR requirements in 2012 because they have assumed that the additional transmission lines have been built by that time period.

What is important to capture here for Santa Cruz County is that this is a county that is today served by a radial transmission line. That county is susceptible to transmission outages of a prolonged nature, and it was out of that concern that the Commission ordered the construction of a second transmission line. That second transmission line has been sited and approved by the state

Siting Committee and this Commission. It is, at the present, going through the final stages of its environmental impact statement with the federal NEPA process, and it's my opinion that that line, if they were to get the okay today, probably would not be available until three years from now at the best.

And so we have -- this Commission has concerns of how do we deal with the customer service quality issues should a transmission outage occur. And there are proceedings that are active dealing with that issue, and I'm not going to take today's time on the agenda to go through that, but simply to refer to that other proceeding if you have an interest in those facts.

Moving to the Phoenix area. One of the key things that did occur between the 2003 RMR studies and the 2004 RMR studies was some clarification of what gets defined as load and generation in the model constrained area. And there were a number of very effective meetings where that methodology was reviewed and hashed out, and I think the outcome of that was that we ended up with the industry being well informed of how the cut plane was being established for the transmission import to the Phoenix area, and that was reflected in the very few number of questions that arose at the most recent workshop regarding how those matters were being defined.

So this is a diagram for each of the years that were studied, showing the cut plane that came out of the study methodology that defined what was to be included as internal to the constraint and what generation was viewed as being effective in responding to the constraint.

The other thing that -- let me also say that the Phoenix area is primarily serving two major utilities customers, Arizona Public Service and Salt River Project, and this was done as a collective model of that system. And once the constraint is understood, then defining how much of that capacity is allocated to each of those utilities determines how much RMR generation each of those utilities must provide to accommodate the constraint.

We have a nomogram addressing this from a system context again that plots on the vertical axis the valley load, both APS and Salt River Project, versus local generation on the horizontal axis. And what we have seen there -- this study is for 2005 -- the cell on the left axis of 8617 megawatts up to a load level of 10,100, where you would have somewhere around 400 megawatts of local generation is voltage limited, and when you get more generation on line as the load continues to grow, it becomes a thermal constraint. And the study work has done an excellent job of defining when you move from one type of constraint to another, and that is I think another key highlight of the 2004 studies, is getting that clarification established.

Then APS took the additional step of identifying a load duration curve. While APS' portion of that constraint helped define how many hours their customers were exposed to RMR conditions, what the seal limit, their portion of the seal value and how much of their load was energy constrained and had to be served by local generation. In this case, in 2005, the RMR energy requirements were 550 kilowatt hours.

Similar information has been provided for each of the years of the study and I'm not going to go through all of that. But what I can tell you is that I saw some significant modeling improvement between 2003 and 2004 studies, and I think the industry also saw that, and was reflecting favorably the value that they saw in the most recent studies.

An area where there has been some discussion between Staff and the study participants is how we go about doing the economic analysis. APS in this case has used a GPS map production cost simulator, modeled the entire WECC system, and have hourly dispatched the whole system as though it were one system, and has come up with the end costs to serve their customers. They did those runs assuming the transmission constraint. They did a second run assuming the constraint had been resolved. And the difference in the values of those two study results is what is viewed as being the RMR cost. And they also use this tool to help them define the emission impacts on running RMR generation.

I would ask you to give some thought to this particular modeling issue, and what we heard from Jeff Miller present earlier in terms of what's coming out of SSG-WI. I think there's some commonality in the modeling techniques, but I think there are things that can be done to improve the quality of the tool to make it more useful. This is a very cumbersome study effort that you have to go through to come up with these type of results and numbers, and I want to compliment the industry for your efforts. I know it was not something that any engineer doing a study relishes doing. It's very labor intensive and involves a lot of work.

One additional thing that came out of the Phoenix area study was a look at local area reserves, generation reserves. And APS put together a red stair step curve here that reflects from the probabilistic perspective what the 99 percent reliability reserve requirement would be based upon the age, size of units that are locally in the system, and then they have plotted in the bars, the blue bars, what the actual reserves that were available from those local units. And you can see that in 2005 and 2008, the local generation was met or exceeded that probabilistic reserve requirement.

Keep in mind that what we have occurring between 2005 and 2008 is some significant generation addition at Santan. That's why you see the number jump significantly in the 2008 time period. But beyond that time period, there is no additional new generation built locally in the Phoenix system. The load continues to grow, and the reserve requirement is still there, and the generation that is local is being used to serve the load and is not available for reserve requirement.

So this is one area of concern that this study highlighted that I think this Commission is very concerned about. And I think there's two answers. I think it implies you build more local generation, or you build more transmission import so that you're not having to rely on the existing local units at the degree that they are.

One other thing that came out of the 2004 Phoenix study was some demonstration of the benefits of having local generation. As we saw in the study results, resolving voltage problems and then moving into strictly thermal conditions, that is achievable because you have local generation. So there's the local voltage support that comes from these units, and the contingency response, if you have an outage you can bring on a unit and pick up load on a restorative basis, and it offers operating flexibility. Local generation also reduces losses and results in a lower transmission investment.

But what the whole RMR study is trying to look at is put in perspective the balance of whether that local generation versus external generation is a better solution. And this listing signifies there's some values to local generation that should not be dismissed lightly.

Let's now move to the Mohave County area. This slide depicts the system that serves Mohave County. And in fact, you heard through the SWAT subcommittee presentations, some more effective detailed description of this that I'm not going to go through right now.

But the area that is bounded by the dashed line is the area that was viewed as the study area, and the load in that area for 2012 was projected to be 586 megawatts. And looking at the generation on the right hand of this chart you'll see the amount of generation that was in operation when the system impact limit was established was 250 megawatts. That was the hydro units at Parker and Davis, with Davis at full output and Parker at roughly 50 percent of capacity.

And the system import limit for this study area in 2012 was determined to be roughly 646 megawatts, which exceeded the peak load, so it was viewed that there was not actually a technical physical RMR condition in this area.

And I'm choosing my words carefully there, because there was considerable discussion at the workshop about what the real problem or issue was for this study area, and there is still some continuing discussion in study work in the SWAT area that is trying to refine and clarify some of those questions.

So the lessons we learned from 2003 studies are as follows: We heard from the industry that they were concerned about the process we chose, the transmission providers only, and they did not have an opportunity to review and critique the results until the Commission's workshop. Those were valid comments and concerns.

There was also confusion and disagreement over the modeling of load and generation in the Phoenix area study, and also there was a question of what the relative operational impact of the various local units in the Phoenix area were in mitigating the import constraint.

Finally, there was the confusion about the Mohave County study in both the 2003 and the 2004 study effort.

So did we learn our lessons? Let's look at 2004. The study process was open to all stakeholders and facilitated a review and comments at each stage of the process. There was improved modeling and definition of the load to generation included in the Phoenix area. It's my opinion that the planned transmission improvements for the most part did mitigate the RMR concerns for Yuma, Phoenix and Tucson areas. And Staff did have the local Phoenix area generation reserve issue surface, and that's something we will want to continue to monitor as we go in years out beyond 2008.

We still have the confusion about Mohave County issues, is there really an RMR issue or are there really technical issues or is this strictly a contractual issue that needs some management.

And finally, I need to reemphasize that Santa Cruz County service reliability requirements are that we need additional transmission lines in Santa Cruz County and until such time as those lines are there, that county is susceptible to extended outages for transmission events.

So here's the big slide you've been waiting on, where is Staff's stand on what all has been on import in the last two years. Staff offers today to you the recommendation that is based upon the hard work that we've seen occur in the last two years and the quality of the work product being improved each year that has been done.

We feel at this point it would be appropriate for us to make this recommendation to the Commissioners as part of our biennial transmission assessment.

First off, all of the Arizona utilities should continue performing RMR studies for all transmission import constrained local areas using a collaborative process similar to what occurred this year, where the industry seemed to be satisfied in playing with the level of participation they were able to offer. That we continue to see the improvement of the economic analysis that accompanies these types of studies, and that we would be seeking clarifying the prevailing system conditions in Mohave County and understand what's really required to mitigate the issues and concerns that are there. Is it something past physical system construction requirement or is it something that is a, can be managed through contractual or commercial practices.

Secondly, Staff would recommend that RMR 10-year study results be filed with the 10-year transmission plans by January 31 of even numbered years to coincide with associated commission obligation to perform a BTA. I think that offers the minimum amount of study work requirement of the utilities and it still affords this commission the opportunity to address the RMR condition on a systematic basis, and Staff is certainly willing to entertain any feedback you may want to offer regarding this recommendation before we finalize it in our BTA report to the Commission.

MR. PALERMO: He said he'd do it in 30 minutes and I've got 29. It's not an opportunity for you to do another slide.

Are there questions for Jerry? Come on, this is your chance to quiz the Commission Staff.

(No response.)

MR. PALERMO: Or are you just really hungry?

MR. BAHL: Jerry, on one slide the number of hours I believe is, APS RMR units in 2012, there were only 12 hours. I think it was the earlier slides. I thought some of the members in the audience might be interested.

MR. PALERMO: Why don't you share the answer with us.

MR. JERRY SMITH: What's the question?

MR. BAHL: Question is the RMR hours in 2012, I thought I saw in one slide in 2012 were 12 hours only, in the Yuma area.

MR. JERRY SMITH: The 230 line. The question is why in 2012, the RMR hours essentially are resolved?

MR. BAHL: From 2012.

MR. JERRY SMITH: Because there was the 230 line assumed to be constructed.

MR. PALERMO: I have a question, then. In one of the last slides you talked about the Mohave area. Pull it up and go through that. There was a particular word that you used, and I wasn't sure what that meant. It was almost the very last slide.

MR. JERRY SMITH: Last bullet there?

MR. PALERMO: No, go to the next page. And even to the conclusion, perhaps. There was one about Mohave and clarifying something, where you were a second ago. That's where it was.

MR. JERRY SMITH: Prevailing system conditions.

MR. PALERMO: What do you mean clarify prevailing system conditions? That's gobbledygook. That's double talk. That's Commission speak.

MR. JERRY SMITH: That gobbledygook is to try to reflect the gobbledygook that we heard in some of the --

MR. PALERMO: I'm leaving.

MR. JERRY SMITH: We actually had a meeting with the SWAT subcommittee that studied this area, and Staff has tried to define what our concerns are, and I believe we have two separate phenomena going on. One is that Staff is concerned about the local service, about the quality of service to customers in that county. And there's also a secondary issue of, and that is transmission delivery potential through that county for multiple parties. And what we're seeking is to understand the interaction between those two phenomena and to what degree there is transmission capacity to accomplish both purposes effectively.

MR. PALERMO: Thank you.

Other questions? I'm not sure if I should stand at arm's length. Any other questions?

(No response.)

MR. PALERMO: Why don't we take an hour five minutes for lunch, so that would be 1:15. And be prompt so we can start presenting the 10-year plans.

(The lunch recess ensued from 12:10 p.m., to 1:15 p.m.)

MR. PALERMO: It is 1:15, and we are going to start with our second panel, which is going to be presenting the 10-year transmission plans. We're allowing two hours altogether for this; we'll take a break before we've used up the full two hours.

I also am going to change the sequence a little bit. We'll have Arizona Public Service go first and then we're going to have Southern California Edison present their part of the interstate projects, because he has to catch a plane and this will get him out of here on time.

I also will remind you, though I probably don't need to do that, that all the material will be presented on the website. The reason I said I probably don't have to is because you were probably here on time earlier this morning, and it's the ones coming in late that didn't hear before that I was trying to say this, all the material will be on the website so you don't have to go asking us or asking Jerry for the material. It should be there in a matter of a day or two.

Again, as we did before, let's have the panelists introduce themselves, from left to right is fine, name and company so the court reporter will have it on the record.

MR. MAVIS: Steve Mavis, Southern California Edison Company.

MR. BOB SMITH: Bob Smith, Arizona Public Service.

MR. KONDZIOLKA: Robert Kondziolka, Salt River Project.

MR. BECK: Ed Beck, Tucson Electric Power.

MR. EVANS: I'm Bruce Evans with Southwest Transmission Cooperative.

MR. COLE: And I'm Perry Cole of Trans-Elec new transmission development, also sitting in for DPA today on the Navajo transmission project. Dine Power Authority for those who don't know.

MR. BOB SMITH: As we get started, I'm going to present the APS 10-year plan as it was filed with the ACC in January of this year. And what I'll do is I'll run through a brief description of each one of the transmission projects, and then briefly try and summarize the changes from the plan that would have been used to perform the second biennial transmission assessment in 2002.

The first thing I want to do is take a couple of seconds to give you a brief overview of the APS transmission system. And I realize most of you know all of this. I think it's pretty easy to see that, the transmission system.

What I will be illustrating is how the transmission system has evolved over the years to bring the energy from the base load power plants, mostly coal and nuclear in APS' case, into the load center which certainly for APS again is Phoenix, and the transmission system in general. EHV being 345 to 500 kV was constructed as early as the '60s for the Four Corners system, and then as the Navajo transmission plan in the '80s, and the Palo Verde in the late '80s came on line, the system has evolved, although you can't see the evolution.

Next year in 2005 we're going to add a second 500/230 kV transformer at the North Gila station, and as Jerry mentioned in the RMR studies, that actually came out as a product of our 2003 RMR report that showed that a second 569 kV transformer at that station would significantly increase import capability and reduce the reliance on local generation. Normally we don't show transformers only if that it's an existing substation in our plan because what we file with the Commission are plans for lines that require siting. However, I wanted to include it here.

The other thing that this project provides is, and you'll see we have been able to defer the 230 kV line that Jerry also talked about from Gila Bend into the Yuma area out to 2012.

The next project is a 230 to 69 kV interconnection, it's a new substation that we're calling Gavilan Peak which will be interconnected into the existing 230 kV WAPA line from Pinnacle Peak to Prescott. This station is going to allow for a new load as it grows from the north Phoenix and north Scottsdale area, so rather than extending new APS facilities, we're going to take advantage of the Western line and provide an interconnection here.

Another interconnection that is timed for 2006 is an interconnection for northern Arizona to strengthen especially the area around Flagstaff. This was in previous plans as a 345 to 230 kV interconnection. What we determined is that it makes more sense economically to initially put in a 345 to 69 kV connection, so APS will be building a 69 kV station with a transformer that will interconnect into the western circuits from Pinnacle Peak through Flagstaff, and eventually goes up to Glen Canyon. There's two 345 kV lines. There's a switching station called Flagstaff that really is a station for the series capacitors, and simply switching those lines we'll put the transformer at that location and build into existing APS transmission infrastructure.

Also in 2006 we'll have the first piece of the Southeast Valley project, and you've heard about this in several different presentations already. It will be from Hassayampa to Pinal West. Then in 2007, and 2011, we'll do the second piece of the Southeast Valley project that, as Rob mentioned, will go to the Siting Committee later this year.

The Pinal West to Santa Rosa piece of it will be built in 2007, then the piece onto what's now the Browning substation will be 2011.

Also in 2007, APS will build a new 500 kV line from the Palo Verde area. We're still determining exactly where, whether it comes out of Palo Verde or one of the IPPs in that area, but we'll build it up to a new switchyard called TS-5 which is on the northwest side of the White Tank Mountains, and this will position us to be able to attach new 230 infrastructure, which I'll show you later in the presentation, which serves the load that's growing currently very rapidly on the east side of White Tanks, and we see later on, even on the north and on the west side of White Tank Mountains.

2009, another interconnection, and this will strengthen service to the Show Low/Pinetop/Lakeside area. And what we've determined to do, we've been looking at several alternatives to strengthen the subtransmission system in this area for a couple of years, and we believe the best solution is to interconnect into a Salt River 500 kV line -- that's the line that interconnects the Cholla power plant to the Coronado power plant -- and build a 500 to 69 kV transformer, again interconnect into some existing APS subtransmission. This is timed for 2009. It's called Second Knoll.

In 2010 we'll extend the new 500 kV project on the west and north side of Phoenix from TS-5 to Raceway, which is currently an existing 230 kV station. You'll see more 230 kV plans out of that area.

In that same year we'll take one of these lines coming down from the Navajo power plant into Westwing, and we will cut that line in and out of Raceway, so Raceway will have three different 500 kV sources. Then as I mentioned, the line that's been on the plans for a number of years from Gila Bend to strengthen the Yuma area, we're now calling this TS-8, we're able to defer that line out to 2012 with the second transformer, the second 500 to 69 kV transformer at North Gila.

And lastly, for the EHV plans, to help serve growing load in the Payson area, we have plans to interconnect a substation on one of the APS Cholla to Pinnacle Peak 345 kV lines, that will be more than likely a 345, 69 kV interconnection we call Mazatzal.

I think you can see sort of overall, that we're adding 500 kV infrastructure along the northwest and the west side of Phoenix, while additional import into Phoenix, export capability out of Palo Verde, more scheduling capability in the Phoenix area, then again along the south part of Phoenix and up into the southeast. So really strengthening the 500 kV into Phoenix by building sort of half an outer ring to complement the EHV that we have closer in.

Now we'll move to the transmission plans, the 230 kV local transmission in the Phoenix area. And again, I think you can see that this system has been built sort of on a hub and spoke system, if you will. We have strong EHV hubs at Westwing in the northwest, the relatively new Rudd substation in the southwest, Kyrene and Ocotillo in the southeast, and then Pinnacle Peak up in the northeast is not 500, but it does have several 345 kV sources.

The first plant addition, and this is just really a repeat of Gavilan Peak substation, so you can clearly see here who we'll interconnect it to the 239 kV line to Pinnacle Peak that Western operates.

The next thing is in 2006, we have sited the West Valley/South project, which is a double circuit. Can't see it on here, can you? Well, there's a substation over in this area called TS-3 that we're going to be building double circuit 230 that will interconnect into this existing 230 kV line from Rudd that goes over eventually to Liberty and on down into the Gila Bend area.

This is attempting to show some 230 kV infrastructure additions further out into the northwest. Unfortunately, it's off the screen on here. As I mentioned, we have a 500 kV line coming from the Palo Verde area up to a station called TS-5, and what I hoped to show was a 230 kV line from TS-5, it will be over here somewhere, into a new TS-1 substation, and that will be built in 2007.

Still just barely out in the screen. In 2008, we will loop that system, which was in 2000, the system sort of down to the TS-3, a substation in the dark, also.

I think this is the last slide I talked about. So TS-5 to TS-1 is a 230 kV circuit tie in 2007. Actually, this is the last one I talked about. Then we're going to complete the loop, if you will, of 230 kV from Rudd all the way back to Palo Verde, to TS-5, 500 kV, and we loop 230 all the way down to TS-3 back in. So from TS-1 to TS-3 will be built in 2008, then in 2012, we'll build this TS-2 substation along that line.

There's a lot of stuff up here. This is all what we sited as the North Valley project a couple years ago, and the way it will phase in, is existing Raceway substation today will have a line over to a new Avery substation in 2008. Again, that will serve load growth in north Phoenix. In 2009 we'll continue that 230 kV circuit all the way over to Pinnacle Peak, and add this substation here, which we're calling TS-6.

A little bit of a backup here. TS, of course, stands for transmission substation, but we like to joke that because people have to put up with all of our changing plans of locations and names with substations, that it actually stands for transient substation.

In 2010, the final part of this North Valley project, at least the APS portion, will be built from Westwing up to Raceway. And all of this was actually sited as double circuit, so that Salt River could at a later date build a 230 kV circuit on the same structures.

You'll notice that Raceway will be served just off of the WAPA Westwing to Raceway line until 2008, and in fact, in 2008 we'll add Avery to that, and it won't be until 2009 that it will be served from an APS station at Pinnacle Peak.

Finally, in 2010, in addition to building the 230 kV line from Westwing to Raceway, as we've already shown, we'll be cutting the Raceway 500 substation into one of the Navajo lines. This is a duplicate view of the 500 line from TS-5 to Raceway in 2010.

And finally, the last project we're showing here is in 2013, and it's a 230 kV line from Westwing to the El Sol substation. This is basically unloading the Westwing/Surprise line that tends to show high contingency flows and is a limiting factor on our area import.

I've got three pages of changes that I'm going to walk through. I don't think I'm going to walk you through every single one of them. You can look at slides of detail. A lot of these are completed projects, new projects that are slightly reconfigured, or renamed projects. A lot of what you see in terms of Rudd, Liberty

South is basically TS-4 now.

Liberty, this is a slight reconfiguration, renaming it. Some substations and some slight reconfigurations for the North Valley project. This Rudd cut-in of Jojoba/Kyrene is something that was a condition of building the Rudd line to study this, and the recent studies that APS and Salt River did together showed that in fact cutting that into the Jojoba/Kyrene line decreased Phoenix area imports, so we both dropped this from our plans.

Again, just some changes, the Flagstaff 345/230 connection instead of 69, some slight renaming of the Palo Verde/Southeast Valley to the Browning project.

One thing I think is significant is the Santa Rosa/Gila Bend line, which has also been in the APS plans for a number of years, has been dropped this year. That line was providing contingency support for both the Gila Bend and the Santa Rosa area, and now, with our plans at Santa Rosa for 500 kV as part of the Southeast Valley project, and the recent construction of the Gila River plant and the Gila River 500 and 230 kV transformer which is very near Gila Bend, we no longer need this line to support those areas.

I think the first couple here, we're taking 500 into Raceway, instead of what was shown on the plan two years ago. Mainly because we see the load growth in Phoenix sort of tapping out in the Raceway area, which is significantly south of Table Mesa. We think there will be better support of load growth building the 500 to Raceway.

And a couple of new projects at the bottom. I think that's about it. Made it through that.

MR. MAVIS: I plan to talk about the DPV-2 project, give you a brief status of where the project is, starting off with a brief project description, talk a little bit about some of the coordination activities with some of the other similarly situated projects and local area needs. Also touch on the status of where the technical studies are, both in the WECC and WATS arenas, and finish up with kind of the expected schedule of some near term of our filing requirements.

But I'd like to preface the presentation by making a few comments, especially kind of going back to the Panel 1 discussions. I think it was quite evident that there was a tremendous amount of collaboration, coordination among all the entities that are involved in transmission planning within these regional forums such as STEP and SWAT.

But I think it's also important to note that some of the individual projects have also been actively engaged in coordinating their specific projects with other entities and their local needs. And I guess one of the big takeaways I'd like you to get from this presentation is that as the DPV-2 project sponsor, Edison has been actively engaged with these regional forums such as STEP and SWAT, as well as individual utilities and developers, to coordinate their specific local area needs and plans with the needs and plans of DPV-2. So I just wanted to make sure that not only at the upper level of kind of major regional transmission planning there's a lot of coordination taking place, but some of these individual transmission projects also individually have been engaged with the stakeholders and the different planning groups.

So with that, I'll jump into, first, again, the project overview. This is a wires project, and for many of you, I guess wires conjures up those skinny little wires maybe in your household. But these 500 kV transmission lines, of course the wires are very big and robust, and add a lot of enhancement to the reliability of the interconnected system. We add new transmission.

But along -- and that's a key element, of course, of this project. It's a 230 mile long line between Harquahala in Arizona to Devers substation, to Palm Springs in California.

Plans to use Edison's existing right-of-way essentially parallels the existing Palo Verde/Devers transmission line. There's other upgrades associated with this project. There's four circuits west of Devers, two circuits from Devers to San Bernardino, two circuits between Devers and San Luis Obispo which will be rebuilt as double circuit transmission lines and upgraded conductors.

Also, we'll be looking at adding some dynamic voltage support to ensure that there's a commensurate increase in the simultaneous capability that was touched on by I think a group in Panel 1, essentially that SCIT import capability, we'll need some devices such as SBCs to ensure that we'll get an adequate increase in that capability, in addition to the East of River nonsimultaneous rating.

The Devers/Palo Verde No. 2 project, use the acronym DPV-2, has a planning date right now of 2009. As far as what was touched on earlier in Jeff's presentation, the need is predominantly economic, adding more energy for the southwest. And in addition, as I mentioned, adding another line to the system should enhance the system during emergency conditions.

This is kind of a pictorial, and unlike what's shown here with the dotted line, it looks like it's on a separate right-of-way, but that's just to be able to view it better. But in reality, like I said, it will be adjacent to the existing Palo Verde/Devers line, and there's about a three-mile segment through the Copper Bottom Pass that has already double circuit tower facilities with conductors strung on both sides of the towers, so three miles of line is actually already built through that pass.

Getting into some of the coordination activities, last November, Edison held a planning review group meeting in accordance with the Western Electricity Coordinating Council or WECC guidelines, complying with project rating activities. And there was a strong showing and quite a bit of interest expressed in this project -- and I'll touch on that in the next slide -- specifically in the Blythe area, and I think it was shown earlier, too, in some of the slides during WAT's SWAT presentation.

There's also been considerable dialogue within the SWAT CRT group. Many of the members that attended the meeting last November later have continued to express an interest in connecting to the DPV-2 project in the vicinity of Blythe and Edison's requested that during some of the assessments that SWAT is undertaking right now, that they come up with some reinforcement plans that we can include in the DPV-2 analysis during our Phase II rating study activities.

These are all the expressed interests in transmission capacity, both on the DPV-2 line and any potential additional reinforcements north and south along the Colorado River shown in blue. And you can see there's approximately a thousand megawatts of interest going west out of the Palo Verde area and over 2200 megawatts, 2400 megawatts going west out of the Blythe area. Again, considerable interest in additional transmission capacity north out of Blythe up to the Davis/Mead area, and Parker areas, and about 150 to the Yuma area.

There's also a developer that has requested reinforcements between the Blythe area and the Devers substation. I think this was mentioned briefly earlier as well. There's an existing Blythe 1 plant, 520 megawatts, some developers that are looking to building Blythe 2 which will add another 520 megawatts. There's discussions right now to try and integrate their transmission needs with DPV-2. They would be -- right now it's envisioned they would build a new 520 line between the Blythe area and Devers. And that of course will be integrated into a new midpoint 520 station at Blythe, then of course we'll have to extend the 500 kV line from midpoint back to Harquahala and Palo Verde, completing the DPV-2 connection.

Another project which Edison has been maintaining a dialogue on is the Palo Verde/TS-5 project that Bob mentioned earlier. The substation is at a location that would -- that's very close to the right-of-way of both Palo Verde/Devers line and the DPV-2 line. And there's some concerns that if DPV-2 is built and TS-5 goes forward and they build a 500 kV project there, we're adding two additional 500 kV circuits in that congested right-of-way area, so we've been exploring some synergies between our two projects to try and optimize line arrangements and right-of-way requirements through that area. And that assessment is still ongoing.

With regard to the technical studies, the DPV-2 project technical study was sent to the California ISO for review. They would have to approve this project to go forward. In parallel, we've been working through the WECC and WATS rating process. We've kind of combined those two processes, I guess, for the sake of efficiency and cut down on travel time and multiple meetings. That's worked out quite well.

WECC has a three-phase rating process, where in Phase III you're actually granted and accepted rating of the project. In this case it would be the east of the river rating. And what has not been mentioned, I guess earlier, is that besides east of the river and SCIT, there's also a west of the river rating or a path that would have to be rated as well. So we'll be looking at both of those during the Phase II rating process.

And as I mentioned earlier, during the Phase II rating process we'll be incorporating some of these other sensitivities, some of these other projects as sensitivities to DPV-2.

And the peer review group meeting is scheduled for July 21. Actually it's going to be a two-day meeting. There's an existing project I think that is mentioned, SWAT presentation. Sempra's Path 49, a great project, will be presented the morning of the 21st. DPV-2 presents on the afternoon of the 21st. SRP's UR 9,000 plus will be presented the following day. So again we're all trying to work together to make this whole process as efficient as possible.

As far as some of the near term milestone dates, again, the ISO is reviewing both the technical and cost effectiveness studies of the DPV-2 project, and the decision is expected to be taken to their board at the September meeting. So at that time, we'll have to decide yea or nay with respect to the DPV-2.

To the extent that we get a green light from the ISO, we would expect to file the CPCN, or certificate of public convenience and necessity with the PUC probably the following month, October, and we would envision that by midyear next year, we'd be filing for the Certificate of Environmental Compatibility with the ACC. So with that, that concludes my presentation.

MR. PALERMO: Thank you.

Because he's going to leave soon, now would be the time to ask questions, I think, just for Steve's presentation, if there are questions now may be the only time.

MR. BAHL: Do you know why the Certificate of Environmental Compatibility application is filed simultaneous with the Arizona Corporation Commission, the filing in California in October? I'm sorry, I got it right.

MR. MICHEL: Steve Michel. Their board just approved the short-term study upgrades I think last week. How does the -- I think there's upgrades related to PV/Devers 1, I guess for that path. How does that affect this project or what's the relationship between the two, the short-term upgrades versus this project? Are they compatible?

MR. MAVIS: Yes, they are. As a matter of fact DPV-2, the assessments, the studies that have been done to date considered the Path 49 or short-term upgrades as being in place, so that actually ends up being the baseline for the DPV-2 studies. As Jeff mentioned, the east of the river current rating is 7550 megawatts. That would go to 8,055 with short-term upgrades, and DPV-2 would be pushing it out to 9255.

MR. JERRY SMITH: Steve, I'd like to ask you to respond, if you can; if you can't, I understand. The question is what degree, as you have been having discussions with APS and the TS-5 project have you collectively, between the parties, been considering the impacts on the risk assessment of the Palo Verde hub, what degree there's improvement in the severity of outages, mitigation of the risk that is there today with the existing configuration; and secondly, as part of your project, do you describe only building from Harquahala to Devers 2, are you also, in that transaction, then buying the Harquahala switchyard and the line back to Hassayampa to be a part of that same line?

MR. MAVIS: With regard to the first question, I might have to defer to Bob. I know APS has been running some studies, I'm not sure about the -- I know some of the studies that we were looking at had to do with DPV-2 and TS-5 together with that. I'm not sure to what extent, if any, the assessments have looked at existing system, as you mentioned. So I guess I can defer that one to Bob.

As far as the second one, I can answer right away. There are some contractual arrangements that Edison has with the generator that would allow us to acquire those facilities. And frankly, I'm not sure where that stands right now, but I know that that is an option that is available to Edison and I'm sure we'll be looking at that as an option.

And part of it, too, as part of some of the problems that are associated with the reliability of having a lot of these circuits close together, owing to the fact that DPV-1 and 2 are real close together, we did consider the double contingency in the assessment, which would involve right now we're looking at an SPS or special protection scheme that would trip generation in Arizona and load in California, but we're also looking at some other options to mitigate that double contingency.

MR. PALERMO: Question back there.

MR. BOB SMITH: Let me just echo that, and to say the planning work we're doing for the Palo Verde/TS-5 project does include assessing the impact of coming out of some of the other yards in the area, the Palo Verde specifically, Sempra's Mesquite power plant and also Duke's Arlington power plant, so we're looking at the reliability of the impact of the various options.

MS. WOODALL: Sir, with respect to your near term milestones, if you file with the California Public Utility Commission for your certificate of public convenience and necessity in October of this year, when would you anticipate that the certificate itself would be issued?

MR. MAVIS: That's kind of a loaded question. If things go very well, I think the rule of thumb is maybe like 12 months, but I think usually it's probably closer to 18 months. So probably somewhere in that 12- to 18-month period.

MS. WOODALL: Could you explain to me the selection of mid 2005 for what year you would be filing in Arizona? Is that when you anticipate your environmental --

MR. MAVIS: That's just a guess right now. As a matter of fact, I was talking with the project manager and I was putting him on the spot because I said, you know, I know there's some interest in maybe about the time frame that we would be filing and he said at the earliest, it will probably be mid 2005. So it's probably mid 2005 to somewhere toward the end of 2005, very iffy right now.

MR. PALERMO: If there's no other questions, before you leave, there is another point I want to bring up that's not related to what you just presented. We are scheduled to have the next panel session here on July the 21st, and Sedina and I were looking at each other in wonder, why did we agree to that, because there's a lot of information. We'll have to write a draft report, we'll have to give everybody a chance to see it, and then have a presentation on that material on the 21st.

And that basically means that there are five or six working days that we have to write this report, because there's a holiday coming up and everything else. So if we work the weekend, that increases our reliability by 60 percent, but it's still not a whole lot. And we have looked at and would like to consider delaying that panel session and presentation of material to August 18th, which is when the next date really that this room is available. And we were wondering if that was going to cause anybody a problem. There didn't seem to be any urgent reason to have it done by July 21st, but I wanted to offer that as a subject for discussion if August the 18th is a problem. Looks like the 21st is a problem for you because you've got something going on then anyway.

If there is a problem come and see me or see Jerry in particular if there is a problem with that, and we'll send out an official notice, I guess, about it.

MR. JERRY SMITH: I think one of the things that it would offer is we know a lot of folks are going to be participating in the meeting that Steve just mentioned is going to occur on the 21st, looking at some important information regarding these projects between Arizona and California, and it would be nice if those parties be involved when we do next meet.

MR. PALERMO: It will give us a chance, because there's a lot of material we really haven't looked at yet, to prepare a better report.

Having said that, one last comment. The next presentation will be by Salt River Project, and when they're done, then I think we'll have questions for projects in the Phoenix area. So if we have questions about that, I think that's the way to go. Then we'll have the rest of the panel present then we'll have questions on the rest of the state, which could affect APS as well. After Salt River Project made their presentation then let's focus on questions in the Phoenix area.

MR. KONDZIOLKA: I think my slide's pulled up. In an effort to save a little bit of time, let me start off by saying that I know the great discussion goes on in the state about education, and there's a little correlation between what the back to basics schools approach and our approach to transition planning is, and we believe in the 3 R's, and that being reliability, robustness and redundancy, with the idea being from a reliability perspective we want a system that could be operated in safe limits. Robustness would kind of address the issue of we want diversity, margin elasticity in the system, and then with redundancy, we'll hear maybe later on in the day we want options in the event there are contingencies or unanticipated events.

What I will do is skip through a couple of these slides very quickly. And one is, I think this would be a fairly common thread through all of the presentation, is we obviously look at making certain we have a reliable system, and we have access to low-cost energy. These are topics we've touched on before, but one thing I would like to really point out is one of the big uncertainties still is that very first bullet point, the dependent upon generation plans. The question we had this morning, why do you have long-term plans, are they worthwhile looking out 10 and 20 years. I hope we have time for this panel here to address that very question.

MR. PALERMO: We have time.

MR. KONDZIOLKA: Mark gave a very good answer, but I think another part I'd like to go into is the plans are out there from a long-term perspective so we know where we're going. If we don't look at 10 to 20 years out, when we do this first plan five years out, how do we know it's going to be the right thing that integrates with what we do the next five years and the next 10 years.

We need to know where we're going, and that's so important. We don't know what generation is going to be added 10 years from now. Our best guess right now is that the next big boom in generation is going to be in that 2008, 2011 time frame, and then what about beyond that? Where is that generation going to be? And where are we going to try and build transmission to develop a system and get it into, say, our example, into the valley. We don't know.

We end up having to do a lot of planning scenarios, and that's what those collaborative planning processes are all about. A lot more work involved, but we're doing more options, but we need to have those options so we know which options to have together best, and that allows us to put the plan together.

I would like to leave the impression with this group here one of the big uncertainties, when we look at any of these long-term plans, is where is the resource coming from. This is not anything new, but I would like to point out that in addition to the N-1 evaluations, we are doing more work in the N-2 or the N-Xs.

Steve just talked about the possibility of having two lines in a corridor. Normally, you would look at the loss of one line or the loss of one piece of equipment. We're doing more work, as we evaluate these systems, to make certain that we have a safe, reliable system from the loss of more than one component where it's prudent to do so. We may not necessarily look at the large venture capital for that particular condition, but we want to have a safe system for that condition.

I'm not going to go through here, you can read this, this is what WECC and NERC define as adequacy, security and reliability, and the point being that when we have our plans up here, what are they trying to accomplish. They're trying to make certain that the transmission we build is built for our customers, it's to make certain we have access to energy. It could be an SRP owned plant, it could be somebody else's, it's most likely to be a combination of those, but we want to make certain that we have the best overall diverse plan that brings low cost energy to our customers.

This is the system today for SRP, and I'd like to point out that there's been a lot of near or very recent additions, when I take a look at what is going on. Browning was added just in 2001. Hassayampa was added in 2002, Jojoba was built in the 2002, 2003 winter time frame. Rudd, the Southwest Valley project, was added last summer, in 2003. Browning was a SRP only project and the other project were joint projects. But a lot of activity has occurred just in the last three and four years.

Bob spoke of the projects looking at 2006. We have the Hassayampa/Pinal West project, then moving to 2007, then the extension over to Santa Rosa, then from

Palo Verde up to TS-5. I put APS on there because APS is lead at this point, SRP is a participant with APS in the project. Bob showed this in 2010, we have the buildout over to Raceway and the Navajo/Westwing line into Westwing. 2011 from Santa Rosa over into Browning. Bob spoke of the siting that's still needed from Pinal West to Browning, and the siting of the Palo Verde to TS-5 and TS-5 to Raceway.

Then I have a slide here beyond 2013. This will be a little more interest to recap, second line from Hassayampa to Pinal West, and included in this segment from Pinal West to Saguaro. There's a note there, I'm hoping you can read it. The primary reason for that is SRP is holder of a certificate on the original Palo Verde down to Saguaro. Right now SRP has no plans on using that, but in the interest of having open information, we've shown this now for a number of years. A change from the original scope two years ago, Southeast Valley project. The project now is a near term all the way to Browning, with a future station sometime within that 10 to 20 year time horizon.

Moving on to the 230 system, this is the system today, and again, I'd like to point out a couple of recent additions. Knox was added for the summer of 2000, and then we also had just last year the addition of Rudd into this system for 2003, and this summer again there's a repeat of Browning. But when we initially brought that on line at 2001, that was just a 500/230 station, with the 230 brought back to Santan. Just this summer we are bringing that on line, so it's also a 230/69 system. We have also added a 69/12 system, we go from direct service from 500 all the way down to 12 right in that location.

The first projects here, some loop in together for 2007. The loop-in of the Liberty to Orme line into Rudd. Then Rudd to Anderson, 230 kV circuit. It's somewhat deceptive on what that scope is. The loop-in at Rudd was contemplated as part of the siting of the Southwest Valley project. There's very little work to be done. The station is already configured and built to accommodate this loop-in, so very little work needs to be done.

Then on the Orme to Anderson line, it's already built double circuit and the conductor for two circuits is already up in the air. Right now they are what we call phase tied, such that the two circuits are tied together acting as one, so it acts as a bundle. So the scope of work, if we do this, is to really untie that and make it two circuits at the station then. Very little has to happen as far as structure, structurally on the poles, but we do need to add some additional conductor.

2008 is the addition of the RS-19 station. APS uses TS, SRP uses RS. We don't have a nickname for RS yet. We'll have to work on that. As we see this line here, this is contemplated to be part of that Southeast Valley project that was spoken of, the portion between Santa Rosa and Browning. This will be a double circuit, 500/230 structure configuration.

And then in 2012, Fountain Hills, you notice it sort of sits there by itself; it's not connected anywhere because we haven't really gotten that far. The last plan presentation showed a 2008 time frame. We have discovered a solution we can implement on the 69 system which has pushed that out a few years, so we are evaluating service to a new receiving station that may be from the 115 level, it may be from the 230 system, and we're also in conversation with APS to possibly do something jointly off their 345 system. But we do know as we look at the load growth out in the northeast portion of it, that we are seeing issues that pop up with the growth that will require the addition of some form of receiving station.

This is a slide which just shows available corridors where we have, in some of these cases like in here, along the Westwing to Pinnacle Peak, that's just open right-of-way. Bob spoke of the North Valley project and we would contemplate that any need between Westwing and Pinnacle Peak would be part of that loop that goes like that.

Between here, between Pinnacle Peak and the Grand Avenue area, we also have open circuit on a structure. In there we have a CEC. All we need to do is add conductor.

These other dashed lines are similar to where there's open right-of-way or there's actually open circuits on existing towers.

Then beyond the 2013, this is very similar from the last assessment presentation to where we're showing that there's going to be needs in our area as it grows out in this direction here towards the southeast valley.

Those of you who are familiar with the far east valley and state land, we initially had a plan which showed 500 through 532 here knowing that from a siting perspective, that was going to be problems. We've reconfigured our southeast valley not to have 500 through 532 there, and to wait until more happens with that land, that development, and then informing them that instead of being the 500 system here, we have more a sense of 230 system through that area.

The 115, this is as it is today and how it's been for a very long time. There's a northern portion to our 115 system, it's that portion up in here. There's a southern portion along here as the Salt River Project. The rest of these are stations that serve mining load or wholesale to APS. The one difference here is this station right here called Spurlock. That is actually a residential substation, it's a 115/12.

And we're showing in 2006 the addition of another 115 to 12 kV distribution substation. We contemplate that it might need siting just due to the proximity of the land we can acquire to where the 115 kV line is. The reason that makes sense to us to go 115/12, versus our 69/12, is we can avoid the amount of 69 kV construction on this fringe area, and then the new station called Carrell can back up this Spurlock station.

And the future plans for the 115 are like they have been for the last 20 to 30 years, they haven't really changed. The mining load, instead of increasing, continues to drop or stay where it is. It doesn't have any projections going up, and so until the load on the system increases, there's just no time frame as to when these improvements will be made. You'll notice as you look, there's actually a parallel 230 system to the 115 system.

Then I just have a few slides here in summary and comparison. This is just going to our 500 system in the red being new, the blue being what was in there two years ago, and I would say very much to what we heard before is on the portion between Hassayampa then around to Pinal West and then Browning, the scope has been slightly revised, and there's been some changes in the implementation, but for the most part it's the same project as far as what it will accomplish. And then coming north out of Palo Verde area, is the TS-5 and Raceway project and the loop-in. That was not in there.

The 230 kV system, again, the blue was in the plan last two years, and then the red being new. The only addition that is new is the loop-in and then Orme/Anderson line.

Then the 115 addition from the difference from two years ago is the Carrell substation. And then I won't go through these line by line, but for the most part this just gives a line-by-line addition as to the changes and whether a date was changed or it was a new project.

That concludes the presentation.

MR. PALERMO: As I suggested earlier, now I think would be a good time for questions for Bob and Rob focused in the Phoenix area, of the materials that they presented, if there are questions. I lay them before you.

(No response.)

MR. PALERMO: I have a question, or a concern. It's not quite in the 10-year period, it maybe falls between there and further out. But that's the concentration at Palo Verde, or Palo Verde and the nearby substations. I have concern that doesn't fall within the normal realm of system planning, it's not N-1 or N minus anything.

But you have a concentration of generation, transmission, control devices that are there that increases the likelihood for unexpected things to happen. Things that you and I would never think of, then they happen, you then go oh, yeah, why didn't I think about that, various timings or relays, or misoperation, or signaling that, you know, a signal goes through of something, and a relay operates, even though that's not what happened. Some of the kinds of things that we saw with the blackout that we had in the east last summer, where devices operated just like they were set up to do, except that they weren't set up to operate when that happened, you know.

And my concern, I mean, it's not an easy thing to deal with because the way to deal with it is to make it less complex by actually disconnecting what has been concentrated, not having as much transmission and generation connected so intimately, it's almost anathema to a transmission planner to say disconnect some transmission facilities.

But I'm wondering if you've been looking at that or considering anything like that in the future, because of the concentration and complexity in the Palo Verde area.

MR. BOB SMITH: One of the conditions I think that came out of the Southwest Valley project in fact was that we do just that, look at those kind of things, because the Staff had the exact concern that with the Hassayampa substation and all the IPPs tied into those, and another line from the Phoenix metropolitan area, the red line from the substation, that need to be brought out.

I think, Jerry, you're going to talk about a study that was performed as a part of that condition, and in fact some efforts that Jerry Smith took forward into WECC to try and get other systems throughout the entire western interconnection to perform some assessment of risk, assessment of things that normally we wouldn't have to take into consideration with the criteria as they exist today. We would certainly look into those things as we plan future projects out of that area, like the TS-5 project.

MR. KONDZIOLKA: I'd like to expand on that a little bit. The question was to Steve Mavis earlier about whether that's being evaluated, and we in SRP have done some preliminary work as to how future interconnections of the Palo Verde hub might help or hinder the problem that you've raised. And certainly when we make our applications for interconnection, we have agreed to do that type of study work to provide to the engineering operating committees for their evaluation, to make certain that when they make their decisions, they're making their decisions with that information in mind.

Again, with the time constraints I didn't cover this morning, but one of the objectives of the siting of the development of the central Arizona plan was to encourage generation to the right locations. As you can see from that presentation, you're building transmission from the Palo Verde/Hassayampa area through central Arizona, then into this northern Pinal area. It's a long ways, and I mentioned that we really want to see diversity and redundancy in this system.

Part of the objective of that process and of the siting is to encourage new generation to be in the right location, so we have generation not just all at the Palo Verde/Hassayampa area, but we see future generation in other areas, and have it balanced to where the load is.

MR. PALERMO: It would seem pretty clear that everything seemed to be drawn to the Palo Verde for a lot of reasons. I mean, there are a lot of reasons why generation, transmission, and everything is there. And it just kind of made me think of generator busing; when you get enough generation, you have to split it because you have so many problems with it. And it's almost like at some point you might need to split those two substations and not have them connected as well together.

MR. KONDZIOLKA: There may be a discussion later on. Certainly the conception at design had that in mind, certainly. As the requests were, they wanted to connect at the Palo Verde bus itself. Part of the philosophy moving forward was to actually build a whole brand-new separate station to add diversity. I think from these other events, we'll see that was beneficial.

MR. PALERMO: This was more for long-term, not something right away.

Any other questions?

MR. BAHL: Can I ask you a question, in fact?

MR. PALERMO: I may have asked my question out of ignorance and I don't know.

MR. BAHL: You talked about missed operation or basically communication, really misoperation which results in even cascading at times, like something happened, an incident happened at Palo Verde a couple of weeks ago when all three units went down.

Talking with Bob Smith and Cary Diese, I got the understanding that they're doing something to the relay scheme to provide reductions at a particular location so that if one doesn't really operate, the other one is a backup.

Am I correct, Bob? Is that what is being studied and is in the plans?

MR. BOB SMITH: Yes. We're going to have a presentation on the next panel, and I'll go into that. We have provided redundancy to those relays if they're not operating operately.

MR. PALERMO: I used the word misoperation, and I meant it in broader sense. The relays may operate properly within their settings and as they were designed, except an event happened on the system that wasn't anticipated and caused the relays to operate within their normal settings, except that gee, you wish they really hadn't operated. It's that kind of thing. It's not misoperation like they did something wrong, it's just an event occurred that wasn't anticipated that caused the relays to operate that would have been better if they hadn't operated.

MR. CHARTERS: Or is it possible developing into a scheme you develop arrays which would on purpose dump the general generation and load?

MR. PALERMO: There's a lot of things, and I hesitate to speak of complexity to you guys, because you've been dealing with complexity to the rapid action scheme in southern California west and Arizona for two decades. So I hesitate to be critical since you've done a pretty good job of it, better than people have done in the east.

But it does concern me when there's so much focused in that one small area that you actually don't have a robust system. It's reliable, it's redundant, but it's not robust, because an unexpected thing can cause a really major problem. That really is more of where I was coming from.

MS. ERIC: I will have more questions on the reliability criteria when we hear all the --

MR. PALERMO: I was trying to focus on the Phoenix area. There will be other questions.

MS. ERIC: The Phoenix area, I have a simple question. When you studied, both utilities, are you now comfortable that the system will operate reliably and won't be dependent on reliability must run units in this next 10 years?

MR. BOB SMITH: Yes. I guess to echo one of the things Jerry said earlier, we did find out in 2012, and obviously beyond, we don't have adequate import to provide the level of local generation reserves that we believe we would like to have to meet the 99 percent reliability criteria, so we have some work out in the 2011, 2012 time frame. Other than that issue, I believe we have very effectively managed RMR conditions.

MR. KONDZIOLKA: I would concur. In fact, some of the projects you see added in here have been added since that study work has been done, and there is a good chance, with addition to those projects, it would move us past that hurdle.

MR. BOB SMITH: I think Jerry mentioned earlier, when he showed you the graph of the reserve and showed the margin how it increased, 2008, he mentioned the power plant additions, but there were significant -- projects that added to significant import capability that add to that.

MR. PALERMO: Is there a question in the back?

(No response.)

MR. PALERMO: Why don't we proceed on with the agenda.

MR. EVANS: As I mentioned earlier, I'm Bruce Evans. I'm with the Southwest Transmission Cooperative.

This is a map of our existing system. Apache generating station is really pretty much in the middle of our system. Just to give you an idea of where that is, that's about 110 miles southeast of Tucson. And so we are out in what is really considered rural Arizona, although we do have a couple of cooperatives that are in areas that really aren't rural anymore.

But we have a couple of 230 kV lines that come out of Apache station at Bicknell. We have a 345 kV line that ties into the Vail substation owned by TEP, we have a 230 kV line that comes up to our Greenlee substation, and from there we tie into TEP's Greenlee substation. We have a 115 kV line that goes to Hayden, ties in with the Salt River Project. The Western Area Power Administration also have 115 lines that ties into our Apache station, which we also tie into a 115 kV system from Bicknell up into what we call the Marana area, so that's where our current system is right now.

I'll go over some of the future things that are taking place. I'll talk a little bit about Winchester here in a minute. We just recently energized that particular substation. In 2005, we are going to be putting in a Sandario substation. We will loop that in and out of our Three Points to Avra line, about 5 miles of 115 kV line. Sandario will go in about the year 2005, a distribution substation, if you will, for our member cooperatives.

Also in 2007, although we don't really show a whole lot that's going on here, we plan on rebuilding the Marana tap in conjunction with the Western Area Power Administration. I think we ought to call that the Jim Charters project. It's nice of you to show up so we can talk about your project, Jim.

What we want to do with this Marana tap is that what we have there right now, we have an existing GOAB switch, 115 three way GOAB switch, and we'll be putting in a switching station, loop into the 115 kV system into Marana substation there, and clean up a problem that we've had for a number of years there.

In 2007 is when we plan on doing the Marana tap project. Also in 2007, we will be wanting to come out of Saguaro switching station with a 230 kV line into a station called Red Rock. Red Rock is also another distribution substation that we have planned for one of our member cooperatives up in that area.

In 2006, up in Pinal County area, we plan on tapping the APS line that goes over to San Manuel and putting in a distribution station there also for one of our member cooperatives.

In 2008, our line that goes from Apache up to Hayden, we'll put in a little station there, come over and tie into the San Manuel substation. That will allow us to get some of our resources out of Apache up into the loads that we have serving a member cooperative that we have in that particular area.

In 2008, we will also be putting in what we call the Bob Road substation, another distribution substation for one of our member cooperatives.

In 2009, we have this line that goes between Marana and Avra. It is a 4 ought line that is going to be rebuilt to 795 to help accommodate the loading we will have in that particular area. So that's projects that we have outlined in the plan that we submitted to the Corporation Commission this year.

As far as changes from the last time we met in 2002 for the biennial transmission assessment, we really only have one change, if you will. We only had one project in our plan at that time, and that was the Winchester substation. We pretty much placed that into service on the 10th of May of this year.

Rob had mentioned that is the first project that really comes out of the CATS process, so we're pretty proud of that project. This is a picture of our 230 kV yard at Winchester. TEP has their 345 kV yard beyond that, and we also have land that has been set aside there for a 500 kV yard, as Rob mentioned, for future 500 kV into that area out of the southeast valley, according to the CATS plan.

Since you're all asleep, we have some late breaking news. On this past Friday we sent a letter to the Salt River Project notifying them that we will want to be a participant in the Palo Verde/Pinal West project. So we're looking at a 3.33 percent participation or 40 megawatt participation in that particular project.

So that pretty much concludes our presentation from Southwest.

MR. BECK: Just a quick overview of TEP's system. TEP itself has a service territory of right around Tucson, which is basically that oval, but Unisource Energy, which is our parent company, purchased Citizens Utilities' assets in Arizona last year, so we now have the opportunity to work with the old Citizens facilities to try and come up with transmission to serve those two new load areas. So I'm going to start with the TEP system.

Since the last biennial assessment, we've had two projects go into service. One is a 500 kV tie up near Tortolita and Saguaro. It's a 71 mile 500 kV tie. The other project is Winchester substation which you've already heard a little bit about.

The Winchester substation does not do a lot for Tucson Electric today; it is more of a support for Southwest Transco, but our long-term outlook is to have future potential 500 kV interconnection to Winchester, which I think you heard about through some of the CATS work.

As far as projects that we had in our plan for this year, we're showing the Pinal West interconnection on our Westwing to South line in 2006, that will provide import capability to Tucson, and allow us access to the Palo Verde market hub for future purchases.

The next line that we're contemplating is actually out in 2012, and that goes from Pinal West into Tortolita, would be a 500 kV connection to just add to our import capabilities into the TEP service territory.

Another project that we're still working on, we've been working on for several years now, is a project down to the Nogales area. It's a double circuit 345 kV line. TEP's interest in that is twofold. One is to interconnect to CFE in Mexico. The other is to provide support to the old Citizens Utilities territory in Nogales. We're currently still in the federal EIS process with that project. We're hoping to have a final EIS out sometime this year, and soon thereafter some decisions from agencies. We already went through the state siting process with the ACC, that took eight months, and we did get an approved corridor. Potentially we're coming to a showdown ultimately between state and federal rights, and it's going to be a real interesting project to watch as we move forward.

Just to kind of recap, we've got the South to Gateway project, which right now we're showing as '05 in service. That's all subject to permitting. The Pinal West interconnect in 2006, and then a tie from Pinal West to Tortolita in 2012. We also had several projects, I didn't put on sketches, but some projects that we've got out kind of as place holders for future, would be another parallel Westwing to South 345 kV line, a line from Tortolita to South at 345. Another line from Springerville down to Greenlee. We have the right-of-way for that, and we actually have probably two-thirds of the distance of that line actually as double circuit power in place across the forest.

We also are showing a Vail to South potential second circuit, and a tie from Tortolita to Winchester. That kind of parallels the old Palo Verde to/Saguaro to Winchester project outlined way back in the past. The way we are looking at that would be to go from Palo Verde/Pinal West to Tortolita and potentially to Winchester in the future.

We have a bunch of 138 kV projects that I did not even attempt to put on this map. There's 22 projects, a lot of them are reconductoring projects. TEP's 138 system specifically serves the Tucson territory, and is really more of a subtransmission or distribution voltage for us and doesn't really impact the grid, per se.

I just want to touch a little bit on the Unisource electric or the old Citizens system. In Mohave County we are a transmission dependent utility, depending on Western Area Power to provide all of our transmission service. And right now we're having problems with future contractual rights on the Western system because they're pulling back at this point.

There are two projects that have potential up there. One that we're keeping our eye closely on is a reconductoring -- actually, that's in reverse order. One we're kind of looking at is the Griffith to North Havasu, which would be a 230 kV line that has already been permitted by the ACC under Citizens' name. UNS has the rights to that, so we have the ability to build that line. The CE expires in 2007. We're reviewing whether we need to start construction, and how to progress with that.

But in the meantime, there is another opportunity up in the northwest part of the system, between Davis and Topock, which is the bottleneck on Western's system right now. There's discussions going on between 3M and Western regarding a reconductoring project using the new 3M conductor, with some efforts I believe through Congress to try and get funding for that. If that occurs, there may be some additional transmission capability that Unisource could use to serve those loads for near term, and potentially push out the need for a Griffith/North Havasu in the future.

This is down in Santa Cruz in Nogales itself. There are transmission issues into Nogales and we're assuming that the Gateway project will get built. Without the Gateway project, Nogales is going to have some real problems having service in the future.

If the 345 line gets built down to Gateway, we would build a 115 line to interconnect Gateway on the west side of Nogales with Valencia substation, which is kind of in the middle of the town. That's several miles long, 115 line to make that intertie. And that would serve to support load in that area for at least several years. We're looking at the next segment of 115 that would be needed, and it may actually fall into the next 10-year plan submittal we do. We did not have it in 2004.

That was basically my presentation.

MR. COLE: We talked about the Navajo transmission project, which I think most of you heard this previously. Just to introduce myself again, I'm Perry Cole with Trans-Elec new transmission development. We've been working with Dine for a little over two years, continuing to develop this project. Dine is part of the

Navajo Nation, and we're looking at building a line basically from the Four Corners region, 500 kV, to the Las Vegas area.

Our company is an independent transmission company. We're regulated by Federal Energy Regulatory Commission at this point with the project we currently have. We're also just building the 500 kV line Path 15 in California. It's about a $300 million project. We're a little on about 70 percent of that, Western Rural and PG&E own about 18 percent.

Just a little background. We're one of affiliate companies. We own the system Consumers Energy system in Michigan and we are not a load-serving entity or a generation. We have no market. We're an independent transmission company which, as everybody I think knows, FERC is most interested in.

Dine has been working on developing this project for quite some time. 1991 I think is when they first started working on this. They were working with various entities, including Black & Veatch and EPG. The permitting status, you can see the record here, record decision was issued in '97, and obtained the work on various issues around permitting the project and right-of-way. We hope to get the federal right-of-way grants later this year.

The purpose of the line is to improve the economic situation for the Navajo Nation, to provide a revenue source for the Navajos, relieve regional transmission system constraints, improve operating flexibility and reliability for the transmission grid, all economic power transactions, and facilitate a future development of Navajo energy resources.

Again, it's a 500 kV line from the Four Corners region to Marketplace in Las Vegas. It's about 469 miles in total. We are looking at it from a development perspective in three segments. The 189-mile 500 kV will be Segment 1. A single circuit from Four Corners area to Red Mesa substations, which we would interconnect into the Navajo lines coming south from the Navajo plant. The second segment is from Red Mesa west of the substation, which would be a new substation to Moenkopi. It generally parallels existing 345 line. And the third segment is from Moenkopi to Marketplace.

This is a map of the projects, Segment 1 being in the blue, Segment 2 is green, and Segment 3 is red. We do anticipate that the line will be initially, probably would be built, Segment 1 first. We're anticipating most of the power needs will be in the Phoenix area versus Las Vegas area. We have been talking to various power plant developers, including, besides coal, in particular

Steag is looking at a 1500 megawatt coal facility in the Four Corners region on the Navajo land as well as several others. Also we've had a lot of wind folks approach us about the possibility of using the line.

Steag continues to develop the plant and is making good progress in all aspects of developing the plant, and we would anticipate they would be an anchor tenant on the line.

I think I'll skip through this, I think it's all pretty repetitive what our objectives are in terms of the segments of the line.

We're currently, as I've mentioned, looking at trying to determine the interests of need for all three segments. If it turned out that most of the power was going to end up in Las Vegas, we wouldn't build all three segments. But it does appear we'll probably be building Segment 1 first or maybe Segment 1 and 2, depending whether some right-of-way issues can be resolved in Segment 2 with regard to some issues that the Hopi Tribe has with regard to some historical significance of the area. It's actually all on Navajo land, but the Hopis have some interest in where the location of the line would go.

Assuming we can get that resolved, we would build Segments 1 and 2 first. We're continuing to evaluate the interests that people have in Segment 3. There are -- we have fed down some information for Segment 3 to be included in the Colorado River transmission planning group, so we would expect that they will take a look at Segment 3 as a possibility to help relieve some of the issues that Unisource has and others have in that region for Segment 3 as a possibility to relieve the congestion in the area. If that were to happen we would need to add a substation in an appropriate location in Segment 3.

That's just a little more closer look at the Segment 1, we're focusing on first.

This is our timetable that we're currently looking at. There's probably a couple months that slip in our timetable from what we've previously projected, but you can see that we're continuing to work on completing permitting right-of-way and licensing for Segment 1. We hope to have that done at the end of this year.

We also continue to work with the regional transmission planning groups, including the WECC process, hope to have that done by summer of 2005. That might slip a little bit in terms of getting all the way through the path rating process. We do anticipate a path rating in this area of 1200 to 1500 megawatts for the rating of this line, based on some preliminary work that Black & Veatch has done.

We're completing the engineering to support all permitting preparation for EPC, engineering procurement construction contract. We're looking for that to be June of 2005. The anticipating issue in the EPC contract later in 2005, we'll probably slip that to the December time frame as we're currently looking at our schedule. We're hoping to be on line late 2008, 2009 time frame.

Again, we're working with, I think everyone knows, Steve Begay. Just to mention, Steve was not able to be here today. We're working on that with them together.

Any questions?

MR. PERCIVAL: Milt Percival, Western. Perry, two questions. The Red Mesa tie to the Navajo transmission system out south out of Navajo generating station, which line were you contemplating tying that into?

MR. COLE: Well, that's not been thoroughly determined yet; we need to do some more studies to analyze that. Steag at this point is doing some study work with APS, and as part of that study option, they are going to be studying the impacts of Segment 1 and we'll be evaluating that a bit further. But it does look like Red

Mesa east, so I think the east line is what we're first focusing on.

MR. PERCIVAL: Is that the express line?

MR. COLE: I think it is.

MR. PERCIVAL: Second question. The Certificate of Environmental Compatibility that you have from the Arizona Siting Committee, are there any conditions on that certificate?

MR. COLE: I'm sure there are. Jerry reminds me that segments -- it does need to be built in segments. Segment 1 and 2 are contemplated ahead of Segment 3, as an example.

MR. PALERMO: Before we take any more questions, I want to take a break. And so we are going to take a little more than 15 minutes. We'll go till 3:15. That, I think, should allow enough time for everybody to take a little caffeine downstairs or wherever and be able to come back. So 3:15, which is like 17 minutes.

(A recess ensued.)

MR. PALERMO: We are going to begin now with questions for the panel regarding any of the material and in any of the areas in Arizona, so please, questions.

(No response.)

MR. PALERMO: No questions. Maybe you're familiar enough with what's happened and there aren't questions. I know that Sedina had questions.

Question in the back, go ahead.

MR. BAGLEY: Comment. As part of the CRT's technical committee in working with Eric on NTP, we determined what was called the 8055 case. It had the wrong presentation for NTP. If anyone else was working on that case we've got the correct information.

MR. PALERMO: Questions.

MS. ERIC: I have several questions related to reliability criteria. Your companies all are WECC members. I would like to know whether, in the process of exploring better reliability standards, in compliance with the WECC standards, whether sometimes in the past it happened that you don't comply with that standard, through reliability management system. If that information is confidential, you don't need to tell that here, but if you are able to tell that, and you have that knowledge, that would be useful just to know.

MR. BOB SMITH: I think from APS' standpoint, from a system planning standpoint we have complied with the WECC reliability criteria.

MS. ERIC: Yes, from a system planning standpoint.

MR. KONDZIOLKA: The same for Salt River Project. I'm not aware of any areas where we were not or have not been in compliance.

MR. BECK: Same for Tucson. I guess I'd only add to that that operationally, occasionally I think all of us have little slip-ups that result in some penalties, but there's been nothing that's been real major.

MR. EVANS: Same for southwest transmission.

MR. COLE: As Trans-Elec Transmission we're a new member to WECC and don't have an operating line, and Western will be operating our line once in service.

MS. ERIC: I'm sure you are all aware of nuclear reliability, if it is ordered. If your control areas went through that, whether you pass or you have something which is problematic from NERC's point of view, I'm not talking about vegetation management report, I'm just talking about system planning and operational issues. You know that NERC had the schedule of all the control areas.

MR. KONDZIOLKA: I can't give you the exact dates. Steve, is it September?

A VOICE: That's a WECC compliance review, different from the NERC readiness audit. We're not getting to those. Maybe next year.

MR. EVANS: Southwest is not a control area. We don't have to worry about that.

MR. BOB SMITH: I think from the planning perspective, we may have had I think one or two 230 kV lines that did not meet the requirement of not having zone three relay. Other than that, we're in compliance.

MR. BECK: Tucson hasn't gone through a NERC planning at this point.

MR. PALERMO: In general what's been your response? I have read your responses towards the proposed NERC standards, and I have the sense from other utilities I've spoken to in the west it is their opinion that a bunch of easterners put together a lot of these rules, and some utilities in the west are struggling with some of them, and I'm looking to see if there's an issue here.

You've answered the question, I just wondered, were there issues that your individual utilities had with the proposed NERC standards.

MR. BECK: Generally as far as the NERC standards go, to a large degree those are eastern standards that fall out of the NERC process. But as far as any particular standard we're having a problem with, not at this point.

MR. KONDZIOLKA: Steve, are there any issues you would say from SRP as far as the --

MR. COBB: No. If we're specifically talking about the policies that were recently rewritten and approved by the NERC board, we don't have any problems with those policies, with the exception of transmission loading relief, which we don't follow. Steve Cobb, C-o-b-b. We have an alternative process in the west.

MS. ERIC: I think we are looking here on transmission planning criteria, not operational. You have different planning criteria and that's not something which is -- which doesn't comply with NERC or WECC, somebody's planning on N-1, somebody N-2, somebody has this voltage limits, the other utility has a little bit different. How you put together these differences when you are planning regional projects through CATS, SWAT or STEP.

MR. EVANS: We all have our own particular planning criteria. Being a member of SSG-WI we require compliance with NERC planning requirements. When we get together, we base everything on WECC planning requirements, the N-1 requirements they have.

MS. ERIC: It was my understanding from the first panel presentation that there were several studies identifying the projects for the Arizona -- or projects, regional, between Arizona and California, and transmission planner retrieved the load flow base case, and grant contingencies and got the results, and he has, or she has to compare with the set of reliability criteria.

And so what I'm looking for is whether in that study one set of criteria is used, or each utility planner is looking particularly at utility criteria, for example, if SRP is using N-1, whether in contingency file, the planner has the exact contingency, if it's double circuit tower or generator plus line, and on the other side, APS has just single contingency, well, line, region and transformer. One part of the system has most region criteria, the other has less when you put that together, the level.

MR. BOB SMITH: I just don't see that in our systems. SRP and APS jointly performed the import analysis on the Phoenix area, and it is for the most part a single contingency analysis. And we're in total agreement on what the contingency list is, what the criteria we have to meet. Whether it's thermal or post transient voltage limitation, we use the same methodologies. I just think there's a lot more similarity in our planning criteria than differences.

In fact, on the EHV system, the WATS committee that you heard about earlier has its own criteria listed studies, that must be held to and must meet despite whoever is running those studies for whatever planned projects. So I'm not really sure where you're getting your idea that we have significantly different criteria.

MS. ERIC: From your reports and from transcript that I was reading, you have N-1 criteria.

MR. BOB SMITH: Uh-huh.

MS. ERIC: You said you have N-2. I was comparing voltage criteria. The limits are different. It was based on that.

MR. KONDZIOLKA: Let me correct something. One is fairly consistently WECC has a very extensive criteria, and I believe we all believe that's fairly stringent and we all meet that. My reference to N-2 in many cases is an operational issue that we're looking at N-2 for safety and system protection, not for planning for additional facilities.

MS. ERIC: Okay. It was my impression that you are planning in N-2 generation interconnection. Who is maintaining generation interconnection queue? Is it one generation interconnection queue for the region or each utility has its own generation interconnection queue?

MR. KONDZIOLKA: Actually it's more complicated than that. One is if it's an interconnection request to a wholly-owned facility by one of the transmission providers, then that transmission provider is providing the queue. In a number of cases there are jointly owned transmission facilities. In the cases of those jointly owned facilities, it's the ownership group. There's usually an operating agent who then maintains the queue for that jointly owned transmission system. So yes, there can be parallel queues out there.

MR. CHARTERS: The other thing is, too, we have been honoring each other's queue dates. If you had a generator ask for an interconnection to you, Ed, we'd say that's the guy that's hooking up to Ed, we'll figure that in the contingencies.

MR. BECK: It comes into the planning process.

MS. ERIC: Generation to interconnection queue publicly available.

MR. BOB SMITH: Ours, it's on the APS OASIS page of Western.

MR. KONDZIOLKA: Once it's official, correct.

MS. ERIC: Each utility is running generation interconnection studies for the applicants on its own queue, or just the group is running studies for those that tie interconnecting jointly owned facilities?

MR. KONDZIOLKA: On the jointly owned facility, the operating agent tables lead in the study work and shares that with the other owners. And then it moves forward through each individual generation interconnection process.

For example, the Palo Verde transmission system has an interconnection procedure, and it has a flow chart. So once an individual who wants interconnection makes that request, they have a procedure and tells them very explicitly what those steps are. Then it's managed by the operating agent who then has a lead study, and in that particular case, there is also an ad hoc group put together which looks at those impacts. Again, just because there are regional impacts typically, based upon those generation interconnection.

MS. ERIC: Again, now reliability criteria, I guess you apply the same reliability criteria when you are planning your system, and when you are adding the new generation or it's something which is most regions, when you are running load flow studies and short circuit studies and stability studies.

MR. BECK: We are running the same studies.

MR. BOB SMITH: Ours, to be consistent with generator facilities, power features.

MS. ERIC: How many transmission projects are required for generation interconnection? In the recent past, because you add a lot of generation in this area, do you have just a rough idea what transmission projects, if any, is added to the system, just for delivery of power?

MR. PERCIVAL: There is no requirement for transmission associated with generation interconnection.

MR. BECK: There's been a rather small amount of transmission added to the generation that's been added. I know the ACC has some issues with having two lines to a generator, so in some cases they've been successful in getting that. But a lot of generation has been added in the vicinity of existing transmission; no new lines were built.

MR. KONDZIOLKA: Let me expand. The Hassayampa switchyard was built exclusively and explicitly for the generators who interconnected or requested interconnection at Palo Verde. The Jojoba switchyard was built as a result of a generator. APS and SRP built the Palo Verde to Rudd project not as a direct result for the generators but as an overall plan to, one, access energy at Palo Verde, to increase the import into the Phoenix valley, but also it did have a lot of positive benefits for the generators who interconnected at the Palo Verde/Hassayampa hub.

MS. ERIC: That's everything that I have.

MR. PALERMO: I'd like to move on to the next panel, which means some of you stay and some of you don't. The next panel is regarding the Palo Verde hub developments.

Again, I think you're known, but why don't you introduce yourselves. Actually, do you know who all these are?

MR. JERRY SMITH: Jerry Smith of the Arizona Corporation Commission Staff. This panel is assembled to address developments of the Palo Verde hub, and we have four agenda items.

I'm going to speak to the first item, which is regarding a risk assessment that has been formed at the Palo Verde hub, some WECC planning guide development activities, and then we're going to have Bob Smith and Rob Kondziolka speak to two events that have occurred in the last two summers that have impacted the Palo Verde hub. And we'll end this panel by asking any merchant plants that are interconnected at the hub that are here that would be willing to share what their experiences, whether positive or negative relative to transmission access and its impact on their operation.

So let me set the stage for this panel by talking about what we're referring to when we speak of the Palo Verde hub. On the screen is a graphic depiction of the infrastructure that exists within a several mile circumference of the Palo Verde nuclear power plant. It involves six transmission lines, three of which come out of Palo Verde switchyard, two to Westwing, and one to the new Rudd substation. Another 500 kV line that comes out of Palo Verde to Devers, and then two transmission lines that comes south out of the hub, one to North Gila, which is down around Yuma, and then the fifth, the sixth line which goes to Jojoba switchyard, which Rob mentioned is a new switchyard, and on to the Kyrene switchyard.

The facilities in this area, we also have interconnected the Redhawk power plant, the Mesquite, Arlington Valley, Harquahala, and the Palo Verde nuclear power plant.

And what we have occurring at this location is sort of the counterpoints of two public policy issues. One is the commercial practices engendered by what has occurred at FERC in terms of Order 88 -- excuse me 888, which establishes direct access on a nondiscriminatory basis for transmission use, their Order 2000, which is the order that was calling for the formation of RTOs to deal with congestion management, their order dealing with the standard market design which was later supplanted by a white paper dealing with market design concepts, and their most recent order dealing with large generator interconnection. Those orders really deal with the commercial practices of the transmission system.

On the other side of the equation is reliability, and this is the area where Staff has been the most active and prolific advocate of concerns at the Palo Verde hub. We have been addressing all of the interconnections and infrastructure interconnections at the hub out of our concern about NERC and WECC criteria regarding conditions that we placed on facilities as they're going through the siting process, and as a part of our retail competition rules, we have a variety of orders that we're dealing with, our expectations of generators relative to transmission service.

To give you some perspective, the NERC planning standard for Category D events is also what is in place for the WECC, and it looks at extreme events resulting in two or more elements being removed or cascading out of service. It looks at a variety of different types of events that could cause those type of occurrences, and simply requires that utilities perform studies to evaluate for risk and consequences, those type of events. And it may involve substantial loss of customer demand and generation, and in a widespread area. Portions of all of the interconnection system may not achieve a stable -- a new stable operating point or evaluation of these events may require joint studies with neighboring systems.

Knowing that the criteria was out there, and what was occurring at the hub, Staff has been concerned that those type of studies were not taking place in this location. In the Arizona power plant siting requirements, Staff has taken the position that's based upon the best engineering practices in Arizona of at least two transmission lines out of every power plant. We have been successful in the siting process at every location except the Palo Verde hub. And that's where we have the largest exposure of a number of plants interconnecting to one location.

We have also taken the position that these plants must meet the WECC single contingency criteria without use of remedial action, such as curtailments of load, unit tripping, or load shedding. Once again, this is a condition that is a little more stringent than WECC, but we have taken the position that remedial action schemes for single contingencies did not seem a prudent planning practice for facilities that were occurring at this hub.

We have also required the plants to be WECC members, and to have RMS agreement compliance for them to seek membership in the reserve sharing group and for 10 percent of the plants to provide capacity for ancillary services to the control area, or RTO as it forms.

In our biennial transmission assessment in Track A decisions, the Commission has taken two positions. First, that each power plant must be -- must ensure sufficient interconnection transmission capacity to reliably deliver its full output without use of remedial action schemes or displacing a priori generation at the same location.

We have also, as a Commission, taken the position that both transmission providers and merchants, merchant power plants, should share the burden and obligation to resolve Arizona transmission constraints.

If you think that's not important, I would ask you how many of the plants that have interconnected at the Palo Verde hub are not generating at a level that is financially viable for those projects because of transmission constraints.

Finally, Staff's concerns of the Palo Verde hub could be summarized on this light. We have been concerned that hub interconnection -- generation interconnected at the hub is of a capacity that's equal to the entire WECC operating reserve requirement, and that plants are interconnecting at that hub via single transmission lines.

All the new plants are gas-fired combined cycle plants that are served, fuel wise, from a common pipeline. And the transmission deliverability of all of those plants at full output has not been delivered except under an ideal situation where the market is assumed to be proportional to the transmission capacity in each direction.

I mentioned earlier our concern that the NERC Category D type of studies had not been performed in the past.

And finally, we have generator only control areas emerging at Palo Verde, where the merchants were, for commercial purposes, gaining status so that they were not under the auspices of transmission control area operators, and that came as a concern, given the reliability issues that we think may possibly exist at this hub.

So in the siting of the Palo Verde to Rudd transmission line, which was Case 115 in our siting process, a Condition No. 23 was placed on the applicants. The applicants were Salt River Project and the Arizona Public Service Company. And they agreed to facilitate an industry review and work to achieve consensus with Staff on the reliability and system security measures appropriate for a large commercial hub such as the Palo Verde. Such measures were to be recommended to WECC for consideration and adoption, and if and when consensus is achieved between applicants and Staff, then the applicants were to work with Staff to initiate action to implement those measures on a statewide basis independent of the WECC action.

What I can tell you is the study work was done. We have moved forward, we have communicated those results with the industry, we have made the recommendations out of that study effort to WECC reliability subcommittee, and it is -- and some draft planning guides for these type of events has been drafted and posted for comments on the WECC bulletin board.

Let me speak a little bit to the study work that was done.

For the Palo Verde risk assessment, APS, Salt River Project and Staff, considered the potential causes of extreme events, and those were viewed to fall into one of four categories: Intentional acts, which includes sabotage, whether related events such as lightning, wind, storms, et cetera, nature initiated events such as earthquakes, subsidence, et cetera, equipment failures or human interaction, unintended action. And I'd suggest, as you stay tuned on this panel, because we're going to hear two events that are related to this last bullet. But all of those potential sources of extreme events were then viewed to determine what kind of outages might come from those events and so the studies looked at the outages of the Palo Verde switchyard, outage of the Hassayampa switchyard, the three tie lines between Palo Verde and Hassayampa, rupture of a common gas pipeline, and a railroad event that could have the effect of disabling numerous transmission lines.

In looking at all of those events, what we found is that while there is a low probability of occurrence, if these events were to occur, we would be looking at losing three to four thousand megawatts of generation at the hub, along with transmission lines that resulted in the study work, and nonstable performance of the system.

As a solution to that condition, we looked at load tripping to see how much load would have to be shed to keep the system stable for losing that much generation, and we found that on the order of several thousand megawatts would have to be shed in order to maintain system stability.

Then the question was posed, to what degree is this something that we need to be taking action for and what are the real consequences of these events. If it was to happen, does this mean that we have extended outage time periods, is this something where the system could be restored fairly quickly. And we concluded that as we looked at new transmission lines that were being proposed and some of which are contained in the plans that you've heard about today, if there was an impact by the location -- termination location at the hub that could help mitigate some of these risks, and the answer was yes.

And it was out of that consideration that the risk assessment made the following recommendations. That future generation and transmission projects should give consideration to risk mitigation for extreme events, if someone is seeking to interconnect at the Palo Verde hub. And for overall diversity performance and risk mitigation, there should be consideration of terminating future lines, seeking an interconnection at generating stations interconnected at the hub rather than the Palo Verde or Hassayampa switchyard.

And it's for that reason in the most recent line siting, which was the Palo Verde/Pinal West line siting case, Staff took the position that we would like to see a provision provided for an interconnection to, in this case the Redhawk power plant, that was the closest facility to the line that's being proposed.

Finally, future generators desiring to interconnect at the Palo Verde hub should be also interconnected to at least one other location in the transmission network. This is intended to help resolve our concern that we had all these plants connected by single lines to the hub, and if you lose the hub you lose all those plants.

So having made those recommendations, presented it to the Corporation Commission, to the Commissioners, and having informed the industry, the next step was to take our results and our recommendations to

WECC for development and consideration of the planning guide.

And I'm going to read to you the language that is being considered today by WECC that is aligned with this issue. NERC Category D, risks and consequences, type evaluations should be performed on all generation hub substations. All types of initiating events applicable to a particular generation hub station should be considered in order to determine how to model the associated disturbances, likely duration of the common substation outage and the cumulative risk and consequences of such an outage. System consequences of hub substation outages may be severe and warrant mitigation measures.

This is in fact some language that responds to the question that you were asking earlier, Jeff, about the Palo Verde hub and all of the consolidation of a lot of the eggs in the same basket.

In addition, the language reads that evaluations of future generation and new transmission interconnections to such generation hub substations shall consider the effect of the proposed interconnection on the cumulative risk and consequences of a common event outage of the generation hub substation. Alternatives to be considered should include the following: Terminating the new line at a different power plant substation currently connected to the generator hub. This is to enable those power plants to remain on line where otherwise they would be lost if the hub was interrupted.

Interconnecting new generation at more than one substation, and mitigation measures including load shedding schemes.

Having that out for consideration has been a big step. I can't today tell you where it's going to end up in the WECC process, but I can share with you the significance of this issue and why it's important to Arizona as well as the west by showing you two generic models of hub concepts.

On the screen I'm showing a Hub A, which has four 1,000 megawatt power plants interconnected at a common switchyard. And that switchyard has four 500 kV transmission lines interconnected. Two are owned by Owner A, and are shown in blue, and two are owned by Transmission Provider B and are shown in red.

We have been told the total regional reserve requirement is 3,000 megawatts. What happens when you lose that common switchyard? You lose 4,000 megawatts of generation, which is in excess of the reserve criteria for the region.

And it's out of that concern that we find that this type of hub configuration is flawed, as you start getting large in scale. As an alternative, if you consider Hub Concept B, the transmission lines still are interconnected to a common switchyard, the hub, but the generators have the transmission lines looped through the generator power plant switch yards. Now when you lose the common switchyard, you have each of the power plants still interconnected to the line that is looped through it. But unfortunately, in solving the reliability concerns with this type of configuration, you're left with the commercial issue.

In Hub A, all of the generators were able to deliver to the hub without any transmission tariff implications, and it was a come and get it market concept. With the Hub B, now, if you have a power plant connected on one of the blue lines that chooses to sell at the hub, the party that's buying that will have to pay the blue transmission provider's transmission tariff to get it to the hub. And if that party that's buying it is taking service, then, on the red line, they also have to pay the red line tariff, resulting in a pancaking of the transmission rate.

The solution to this is by redefining the transmission tariff rezoned to move it from the hub all the way out to the interconnection of the power plants.

Staff has had some conversation with FERC staff regarding these concepts, and we have collectively, in preliminary discussions, concluded that there is a need for policy and regulations that balance reliability needs and market interests at these type of large hubs. We've also agreed that generator only control areas are acceptable only if reliability obligations and purposes are also being maintained. If you're only creating, for commercial purposes, to circumvent the reliability obligations, then it's not the right thing to do.

And finally, the exempt wholesale generator substations and embedded lines that today are not involved in the transmission network should have the same obligation to request interconnections as the transmission provider would have.

We've heard today about the Palo Verde/Devers 2 interconnecting at the Harquahala power plant switchyard. It's saying Harquahala should not have the ability to say no, but say here's what's required for the interconnection.

Exempt wholesale generator substations and embedded lines should also fall under a transmission control area operator because they would be operating as part of the transmission network. And tariffs should be present to avoid pancaking of transmission rates as new interconnections are made at those substations.

And finally, there must be this demonstrated deliverability from a reliability standpoint. This is the area where we have had the most difficulty to date at the Palo Verde hub.

Having set the stage, we're going to now have some actual events discussed to help put in perspective to what degree are these real concerns or are these issues that are subtle that don't have a lot of need for action.

MR. KONDZIOLKA: Up until now we've talked about a lot of positives. Now we're going to talk about one of those not so happy events. I think the good thing I'd like to report on or state that Jeff made some comments about the northeast blackout and does the development of the Hassayampa/Palo Verde hub maybe contribute to some northeast style or implications. And at least I'd like to preface my comments with that I don't see a lot of commonality between the events that have happened at Palo Verde and the northeast.

Specifically, if you read the report, the issue of situational awareness, that doesn't come up out here. There's good situational awareness. Communication with others, I think you'll see that communication is very good. Adequate regional visibility was another issue from the northeast. I think this will demonstrate that there was good regional visibility, operating within limits.

That wasn't an issue here, and vegetation, trees, was not an issue. However, there was something very, very bad that was occurring here that we'll cover.

And I guess the last comment is the content of the presentation material is consistent with the results of the WECC investigation, and it is understood that major events like this normally will have a WECC investigation, and a report which then goes through the operating committee of WECC for final approval, to make certain that it was done properly and it improved.

Starting off, last summer, it actually was a fairly typical summer. Up until July 28th at 6:54, things had been good. In fact, this particular day was a fairly typical hot day, it was not overly hot. Capacity wise, things were very good. APS and SRP had added the Palo Verde to Rudd project, so there wasn't really much of an issue as far as allowing generation beyond the hub. There weren't constraints there, there were not problems with deliverability. But as you can see here, some generation tripped and then load was impacted.

So where did it get tripped? Unit 3 was lost at Palo Verde and it was pretty much at full output; Redhawk Units 1 and 2, 760 megawatts; west Phoenix, about 43rd and lower Buckeye --

MR. BOB SMITH: Just Buckeye.

MR. KONDZIOLKA: Harquahala Unit 2 at a much lower level. I'll point out right now, Harquahala was not commercial, it's still in testing mode. Some of the issues associated with Harquahala may still exist because it hasn't gone commercial.

Recap here, just to keep in mind what happened, APS had to trip 440 megawatts. It was actually shed. It was systematic. It wasn't lost instantaneously. And the reason is when the amount of load was, generation that was lost, you can see here 1800 of it was APS'. All the other owners lost significantly lower amounts, and I put a note in here that the largest amount by any other owner was 220 megawatts.

This is actually rather simple. The key word right here is grounding switch left closed. Arlington Valley had some issues up until this point with trips in their system due to contamination on their insulators right next to their power plant. SRP was doing some maintenance on the line and it was isolated here at Hassayampa. In the evening, when the work was completed, and the line could then be reenergized, it was going through the normal sequence of events. A troubleman was on-site, he called in to power operations and was walking through the reverse events of isolating it to put it back into service. And this was where you've got to say it was just a simple uh-oh, where the troublemen didn't recognize the switch being in the open and closed position.

The operator at the time had asked them if he opened the switch, and he said it's already open, and that caused immediate concern with the operator and he asked him to verify that. After verifying that yes, it was open, they went through and closed the switches, and then before closing the breakers asked again to verify that the switch was indeed in the open position, because it appeared that from their records it was still closed. He verified it was open. The rest is history. Once the breakers were closed, there was a three-phase fault right at the Hassayampa switchyard.

So why is that so important to Palo Verde, which was probably the biggest issue? You see here, here's the Hassayampa bus, very simplified. Here's the Palo Verde bus, three generation units, Palo Verde, and you can see that this distance here is only two and a half miles between them, and there are three tie lines. Essentially, it electrically acts as one switchyard. For scheduling purposes it is one switchyard. But with this Arlington Valley plant in here, and this left in the closed position, when it was introduced, you introduce that three-phase fault into the system and it was close to Palo Verde.

What we have found from previous study work, we've studied single phase faults, and three-phase faults, and in some cases the things are much more sensitive as you get closer into the switchyard versus being further away.

Good news is when this event happened, the southwest reserve sharing group was activated, and it was activated really just as you would expect, and this is why it made an event like this much less impactful than it might have been. So there was good response from the southwest reserve share group as to the reserve generation.

I think another thing to point out is if you look at this time line here, you can see, this is not that large a frequency drop, down to 59.79 hertz, and down here is shown the first step of the underfrequency load shedding done at 59.5. So it was not dropping down to hit the preset other frequency load shedding areas which are throughout the west.

I don't want to spend a lot of time on this particular item, but I want to point out one thing, because when we show the time line, it's important. When you look at the event happening here at 6:54, you see frequency initially drop and then it was rising, and then just before the hour, it started dropping. And it was in this stage here that caused APS, in their coordination with the reliability coordinator up in Denver, to request and agree that load shedding should occur. So it was a conscientious decision to shed the 440 megawatts, to make certain that this was completed from and brought any further then of course to come back to normal.

So looking at the events, the trips here at 6:54, the southwestern reserve share group was activated, reliability coordinator is notified. At this time here, seven after the hour, there's a mutual agreement to shed load. 440 megawatts is shed, and then you can see here that it's implemented. And then an hour 20 minutes, approximately, afterwards, load is fully restored, system back to normal.

Just noting here, when the other units that tripped off line and came back, you'll notice here that Palo Verde wasn't brought back on till August 4th. Again, that's a whole other issue between a nuclear unit and then a gas or a coal-fired unit.

I think, Jeff, this fits into your question earlier, and certainly this is one of those issues why did the generators trip, and they all tripped for different reasons. And the first one is Palo Verde Unit 3 tripped, and the first point is it had a valid trip. It sensed properly for what it was seeing, in hindsight, and under evaluation, it was determined that that setting was no longer needed for where it was, so it has now since had some of its settings removed.

However, the other ones, when we look at the Redhawk Unit 1 and 2, it tripped on over frequency, so yes, that was undesirable trip, and it has since been modified so that it's had its over frequency set higher I think to about 62.5 hertz, so that it would not trip in an event like this.

I know you'd expect the opposite, but Harquahala Unit 1, this is a little more unknown, that it's still in testing mode, and in fact it's still in testing mode. So the final report has left that a little open with a key issue being that it should meet the full WECC criteria before going commercial.

Lastly, the West Phoenix 5 had an over frequency trip relay, again undesirable one. Manufacturer identified to set, to be modified to be appropriate for WECC criteria.

In conclusion, the systems were operating per WECC criteria prior to the event. Proper communication and procedure were followed after initiating the event. The third conclusion, the troubleman obviously was not trained for what he was doing.

Also, looking at the way in which the

troublemen at work were trained, the adequate system was not there to verify they had received proper training in certification. That has since been completed such as there is a training program, and there is a way to notify any troubleman operating in the Palo Verde and Hassayampa switch yards. Then along those lines, there was discussion about should there be visibility in the SRP system operations to be able to tell if a ground switch is in an opened or closed position. In lieu of doing a lot of things right now, turnkey interlocks have been installed so that it now becomes impossible to close a breaker into a closed switch.

And then lastly, generation trip to overly converted settings or undesirable protection operation, all those have be corrected and implemented.

MR. BOB SMITH: I'm going to forward in time, close to a year now or go back to two weeks and cover another event. Jerry mentioned five potential causes of these things, and Rob just took care of the human error. Now we're going to talk about the equipment failure, although some people might claim there was an intentional act only just not by a human.

On June 14th I was in Massachusetts on vacation with my family, and we stayed pretty busy. We saw Boston, went to Cape Cod, went to New York a few days, so we really weren't paying a lot of attention to the news. I can't tell you if this got any coverage back east or not, but the first I heard of it was the following Saturday when I was running through all of the messages on my pager. And everything is pretty normal, you know the system status of the day, and I come to this one, and it says Palo Verde Unit 1 returning on, and the time and date, then I scrolled down a line and it said Palo Verde Unit 2 returning on time, then when I saw the third one, I wasn't sure what happened but I thought it couldn't be good.

On the morning of June 14th, again, a lot of things are similar to what Rob just told you. The system really was operated reliably under very little stress at all. We were probably at about 60 percent to 65 percent of our peak load in the Phoenix area. All of the equipment was in service, we didn't have any significant outages, power plants were operational, and really, things were looking very good for the day. I think we had a peak maybe of 90 percent of our expected system peak that we see later in the summer.

The initiating event was a fault on a 230 kV line out of Westwing, and I think Jerry also gave us four or five scenarios that you studied when you did the hub assessment, you looked at gas pipeline problems, you looked at problems at Hassayampa, you looked at Palo Verde problems, you looked at railroad issues, the ties between Hassayampa and Palo Verde, but you failed to look at the 230 kV line out of Westwing.

And I think that there are two lessons here. One is, however hard and however long you spend trying to simulate what you think might happen so you can put protection for that specific event, you'll never get the one that's actually going to happen.

Which leads you to, I think, the second important point, which is the importance of safety nets. Again, the system wasn't terribly stressed on this event, you're going to see we didn't have a whole lot of underfrequency relaying about the safety nets we had in WECC for a number of years now both underfrequency load shedding to protect for large resource losses, and more recently we've been seeing under voltage relay added. We had a significant amount between APS and Salt River Project here in the area. You have a gauntlet for additional outages such as what occurred on the northwest side of Phoenix on June 14. This occurred at 7:41. In the morning, unlike the event back east, this was very fast, it all occurred within seconds. The thing was over and in fact restoration was fairly quick.

Very significant, all off-site power was lost to the Palo Verde switchyard. This is something that we update procedures every year to be able to provide what we refer to as black start power to the Palo Verde switchyard, so you can have safe shutdown of the nuclear unit. Each one of these units have two diesel generators. Of the total of 65 of them operated successfully on this day. It's a big deal to NERC to have all the power out on -- plans for black start procedure allow for up to four hours of lost power. We were within 30 minutes to the positive.

In addition, all of the power at Palo Verde we had a total outage. Westwing 500 kV and 230 kV switchyards, a total of 4600 megawatts of generation was lost, 4,000 lost to the proposed Palo Verde to Hassayampa. From a resource outage this event was more significant than any of those. About a thousand megawatts of load was impacted.

What you're looking at here is a picture of the towers that not only is the Westwing/Liberty line, which is the line that initiated the event, first fault, bird also on this same tower, on the other side that you don't see over here, and it's not the projector this time, but that is the Liberty/Agua Fria line, so you have a double circuit on a tower.

And what initiated the fault was you had a rather large bird sitting up on top of this top structure that would hold the top phase that had been digesting his dinner all night long. At about 7:41 in the morning it decided to take off and I guess try and decrease his weight as he was leaving the structure, and the stool got all over the insulator, which you can see in this picture has already fallen down into this lower phase and arcked across it, initiating a Phase C, which is the top phase here, to ground fault.

After 13 seconds, this fault had traveled through this phase, which I think within about six seconds it turned into a two-phase ground fault, then after 13 seconds it probably went over to the tower to the lower conductor and became a three-phase fault. The fault was on the system for a total of 39 seconds, and this is a very, very long time to have a fault. Faults usually clear for primary protection on an order of three, four cycles; cycles are 1/60th of a second. Even if you wait till the backup protection kicks in, you're still talking in the order of 10, 12, 15 seconds. So for a fault to remain on the system for 39 seconds is really remarkable.

What happened is you had a failure of both the primary relay for the Liberty to Westwing line, and the backup or breaker failure relay. I'll show you some diagrams in a second, but what we found out was that at the Westwing substation, out of all the lines out of the 230 bus, there are two lines that still are protected by the old electromechanical relays. One is the Westwing/Liberty line, the other is the Westwing/Deer Valley line, you still should have redundant relaying throughout the system for both primary and breaker failure backup.

However, we further found that both of these lines, the old relaying had a single point of failure in an auxiliary relay that in this case had four contacts, and only two of them were made up because this element that comes down to make contact kind of fell down sideways and got stuck and only made two of the contacts. The contacts that did not make up were the contacts that went to both the breaker that did not operate for the primary protection, and the trigger for the breaker failure for that same relay, so neither of those schemes operated.

This is a diagram of the Westwing 230 kV substation and the configuration is what we refer to as a breaker and a half scheme. Each element coming out of the bus shares a dedicated breaker on the bus sides and a middle breaker that was shared with the opposite element in this same row. We refer to these as bays. So for the Liberty/Westwing line it's the same fault. Normal primary clearing would have, and correctly, opened at Liberty.

At Liberty there's a different configuration, it just has one breaker; it opened as it should have. At Westwing this middle section breaker did open correctly. However, this breaker 1022 was one of the breakers that failed to get the signal from the auxiliary relay and did not open. So you have an opening here, and at the Liberty end of this line, but this breaker hung on. Normally, if the backup relay or the breaker failure relay has been activated, it will sense that this breaker does not open, and then it will deploy again within maybe 10, 15 cycles. That scheme would open up all of the other breakers on this bus that would then isolate this bus from this line. Actually, you deenergize this breaker, if you will, by isolating this bus. Again, this failed to operate.

So what happened, then, in the next 10, 20 cycles is that all of the rest of the 230 kV at Westwing opened either at Westwing or at the remote ends on their backup protection. The 230 lines have additional protection to the primary relaying that looks beyond just that line and will sense a prolonged fault beyond its protection. Those relays in general operated certainly within the first second, and probably on the order of 20 cycles, so the 230 bus cleared relatively quickly. What was left were the three transformers coming in from the 500, feeding power to this fault into this line. There is not protection designed on the transformers or the 500 kV system to sense these kind of faults, and for reliability reasons you don't want the 500 system to open up for any fault or the 230. The 230 equipment is designed to clear this.

So you can see all of the lines out at Westwing, including the 69 kV transformers that are opened, and the only thing left are the three transformers to the 500 station. And then over the next 39 seconds you had an extensive amount of 500 kV open up.

Relatively soon into the fault, you had the three ties between Palo Verde and Hassayampa open, and that set off a significant voltage drop at the Palo Verde switchyard which fooled all the other 500 kV lines into thinking that they were seeing faults. The significant shifts on the system, the disturbances, the lower voltages, the frequency excursions, the lines are thinking that it has a fault on those lines, so they're not really relaying out for the right reason, but they were seeing what they're supposed to see.

So at this point, the three Palo Verde units obviously tripped off line because there's no more lines out of the Palo Verde yard. You've lost all the 500 kV into Westwing, and you deenergized the line at this point. So this is the status after the faults cleared.

As I mentioned, 4600 megawatts of generation tripped off line, 3780 of it was the three Palo Verde units. Redhawk 1 and 2 were on line, but they're capable of close to a thousand megawatts, so they weren't really significantly loaded. They tripped off line on zero sequence, which means that the system was unbalanced. It was at a time when either the single line or the double line to ground fault was on the system. The Duke unit, actually the line, the single line from the Duke plant to the Hassayampa tripped off line which took that unit off, and then we even got Alberta, Canada involved. We had a generator in Alberta that I believe on interfrequency relayed off line.

There's an extensive amount of load, mostly in the southern part of the system. And I won't run through the numbers but SRP, Pacific Gas & Electric and San Francisco, APS, Tucson Electric, Excel it is now, used to be PIESCO and Public Service Colorado is probably the Denver area. ADSO is up at Alberta, they got a little load to go with their generation, and Public Service New Mexico.

This load is a combination of underfrequency load shedding, load that would go off on its own, not necessarily from feeders opening up, but just load that's leaving the system at the customer location because of undervoltage or some other issue that the load itself is sensing and shut itself off line. We had some of that in Phoenix, and at least for APS we did manually shed some load in an attempt to get into balance in the system. It turns out the frequency came back rather quickly and most of this load was restored within a couple of hours.

I mentioned the underfrequency load shedding, and earlier, in the presentation I talked about safety nets. WECC does have an extensive underfrequency load shedding scheme, and for most of the utilities in the southern portion of the system, the highest setting is 59.5 hertz. So any time the frequency dips to or below 59.5 hertz, you would expect a significant amount of underfrequency load shedding.

In fact, if it dropped low enough to actually trigger all of those relays, you would lose about 3,000 megawatts of load on the system. You can see we got very close to this. This chart shows something close to 59.5, 4, maybe, but that is going to vary at different places in the system, and that caused some of this load we looked at to trip off line underfrequency.

The other significant thing I think about this line you can see within roughly 20 minutes, from 7:41 up to more like 18 minutes, the system has returned to normal frequency. That's pretty amazing, within 15 minutes to be able to make up 4600 megawatts of generation. I think that's probably because it was early in the morning, load was light, there was load coming on to meet the higher loads in the day.

We actually reversed the flows that we see from Arizona to California. Flows were coming into Arizona. The restoration of the system, Redhawk came back on line about an hour and a half after the events, Duke Arlington, maybe an hour after that. You can see the Palo Verde schedules here, and this was really nothing that -- it didn't take the units this long to get ready, but there was a lot of activity with the NRC to make sure that the NRC thoroughly understood what happened, why the units were shut down, were they shut down safely, were there any issues that we needed to fix right away. It wasn't until they had given Palo Verde operations folks the go-ahead that they can come back on line. Again, you can see when the load was restored with APS and Salt River.

This is the restoration of the transmission, and as I mentioned earlier, within 30 minutes of the outage, we restored off-site power to Palo Verde. This is the first item here. The Palo Verde/Hassayampa Tie No. 1, which was closed, which energized the Palo Verde bus. 10 minutes later, the Palo Verde/Westwing line was closed which energized the Westwing 500 kV bus. By 8:30 all of the 500 kV facilities were back in service except for the Palo Verde/Devers line. It was really later that afternoon, not because of anything at Palo Verde, but Southern Cal Edison had some issues with switching series capacitors out on that line, and some other voltage concerns, and it was decided by the operators they were going to wait until that evening to put that line back in service.

The 230 bus at Westwing was energized at 8:56. By 9:52 all the Westwing 500 kV facilities were restored. And by 10:00, about two and a half hours after this event, you really had everything back in service. Obviously the 230 lines that were on that tower were damaged and the Agua Fria line was a problem with the static that was fixed later that day, and it was returned to service, and then it was two days later on the 16th, when the Westwing/Liberty line was put back this service.

Rob mentioned WECC disturbance investigations, and certainly, this was in the category of a major system disturbance, and a major detailed system disturbance report has been requested through the WECC chair operating committee, and CMOS operator, reliance subcommittee. When you have these emergency services, they would rather have someone outside of the area chair it. They have chosen Doug Hinks from the Alberta electric system operator.

There are 20 people that have expressed an interest to participate in this investigation, and the first task force meeting is going to be scheduled sometime between July 6th and July 17th.

WECC sent out a letter to all operating entities telling them to save their data, collect all the data that would be necessary to rebuild this whole scenario in a model so that we can do analysis with power flow stability, those kind of things, and that data is due to WECC on July 1st. This is very aggressive, but they want to try and have a final draft report to be complete for the August 11th CMOS meeting of this year so that the OC that probably meets in September will be able to review the report and approve it.

One of the things that happens in this WECC disturbance report investigation, we've been doing this for a number of years, is that the report will look at compliance with criteria before the event, see if there were issues like communications, observability to grid, were there any extenuating circumstances that exacerbated the disturbance itself, and finally, are there recommendations that we will need to make to improve things. Whatever recommendations come out of the reports will be tracked, and whoever is responsible for actually doing that report will have to report to WECC three times a year as to the status of the implementation of these recommendations.

Finally, in the long-term recommendations, I don't know what will come out of the service report, but we find three quick hitting things to make sure this doesn't happen in the future. Obviously the lack of redundancy for both the primary and breaker failure relay was building, and we took care of that within days. By June 16th that was done not only on the Westwing to Liberty line, but also on the other line that had the electromechanical relay on the Westwing to Deer Valley line. Both those lines also will be changed out to solid state relaying, which is much more reliable, in the fall of this year. Actually before this happened they were scheduled to have that done.

And the last thing, it was felt that if we had opened up the transformers from the 230 to the 500 earlier into this event clearing the fault, because all the 230 opened up relatively quickly, we could have saved a lot of the problem on the 500 system.

In addition to the primary and secondary relaying on the 230 we're going to put some additional relaying. I don't think we've got the exact design down yet, but we have some ideas that will basically look into the 230 bus, and say hey, is there a fault there that hasn't cleared in some reasonable amount of time that you would expect it to clear with either the primary or backup relay, and if so, say I'm going to open up the transformer to save the 500 system, we're going to do this at Westwing in the next couple months, and APS is going to look at the other 500 buses on our line and do the same thing with it.

I think that's all I have.

MR. JERRY SMITH: Last part of this panel was to seek comments from merchant plants interconnected at the hub, related to your experience to the transmission of the hub. Do we have any here?

I'm not seeing any here, so... All right. That concludes this panel, then.

MR. PALERMO: Any questions? Are there questions?

COM. GLEASON: Mike Gleason. The newspaper account of that out there said there were several big bangs that went down the line. Was that line damaged in several places as a result of that? What was this noise that they heard out there on that?

MR. BOB SMITH: I don't know that.

MR. KONDZIOLKA: Commissioner Gleason, yes, there was extensive damage away from just that single point. SRP had to replace, I don't know the exact amount, but a large amount of that overhead wire. It had to repair the conductoring in many places where it dropped in and arcked over. So yes, there was extensive damage, and probably those wires had to be replaced over a section of miles, then the conductor had been spliced, and what we call a repair where we have a rod which overlays a conductor to, one, keep it from arcking or have any type of corona to make it smooth again, but also structurally.

COM. GLEASON: Thank you.

MR. MENDOZA: Steve Mendoza. Bob Smith, I was just kind of curious, how often were those relays scheduled for maintenance and how long had it been since they had been maintained?

MR. BOB SMITH: I want to say we do that every two or three years, Steve. I don't know the exact date.

Cary, do you know that, by chance?

MR. DIESE: I don't recall that, but we had two functional tests. In the last year, we had two other faults.

MR. BOB SMITH: They were two nonintentional functional tests within the last year where we actually had a fault on that line, and the relays did operate.

MR. PALERMO: Thank you.

We have one last session addressing national regional issues, and Jerry, I'm not quite sure who is doing that. Anybody? My sheet doesn't have any names on it.

MR. JERRY SMITH: Charlie Reinhold, Steve Cobb Mike Neal, Ed Beck, Bruce Evans and Steve Mendoza.

MR. PALERMO: Gentlemen, recognizing the time, perhaps you aren't aware, but 20 minutes, comments will have to be brief. And I'm not quite sure how we want to address this. I'm kind of collectively trying to get some kind of reaction. There's six issues. 20 minutes, we're not going to spend a lot of time on six issues in 20 minutes. Therefore, I'll exercise some discretion here. Let's not discuss right-of-way vegetation management. I'm assuming that's not an issue. I mean maybe fires are, but I don't think --

MR. NEAL: They are.

MR. PALERMO: Fires are, vegetation is not.

MR. NEAL: It's a big issue.

MR. JERRY SMITH: Let me suggest maybe two real quick and short ones might be the WestConnect update and the federal reliability regulation.

MR. PALERMO: WestConnect.

MR. REINHOLD: I'm Charlie Reinhold, WestConnect project manager, and I will dispense with PowerPoints.

A couple of quick things. We are continuing evolving through the phased approach that we talked about several times in public. We had a stakeholder meeting last month, received some good comments. We intend to have a follow-up stakeholder meeting in the September time frame, and they're looking at quarterly thereafter, so it will be a little more often we'll be seeking public input and providing information.

One of the big pieces of WestConnect's phasing was the implementation of the West Trans OASIS system. For the WestConnect participants, they went on line at the end of March with that. As of today, the second phase participants have come on board, all but one. Texas, New Mexico went live about three weeks ago. Portland General Electric, Northwestern Energy, and western Phoenix office are going live sometime today. They will be on the system tomorrow. Idaho Power Company is taking another 25 days because they're implementing the full scheduling option within the OASIS as well. So as of the end of next month, there will be 19 transmission providers within the western interconnection on West Trans. I'll stop there.

MR. PALERMO: Thank you.

Federal reliability legislation.

MR. BECK: That will be real quick. As you know, last year there was a process going on where one house passed a bill, it went on to the other and was not approved. Subsequently, this year there's been new bills introduced. One I understand just passed, I believe it was the House, and was transferred over to the Senate, but we're waiting to see what the status of that is. It's critical from a national perspective to get some reliability rules in place across the whole country. It's not as critical for WECC because we already have our RMS in place.

MR. PALERMO: Speaking from Washington, not this year, it's not going to happen. How about the August 14th blackout implications?

MR. COBB: If you want it quick I can give it quick. I'd say this is one of those situations where we had a couple slides, one showing a stake, and one just a quick retrospective, in 1996. Many of you in this room will remember when we had a large blackout in the western United States. That was August 10. And from that experience we implemented a lot of measures within the WECC, 140 plus, to help mitigate those kinds of problems of the future.

Now the WECC has cleared those items, and what's interesting about that is that the blackout that occurred in the northeast last year, a lot of those same mistakes were repeated. So from a WECC's perspective, the recommendations that have come out of the joint U.S./Canadian task force that investigated the northeast blackout, some of those recommendations are already being covered in the west. As a matter of fact, some of the things that we did in response to our blackout in '96 are being used as templates by other areas of the country to implement mitigating measures.

So from the perspective of WECC, and I think Bob Smith and several others have touched on the way we process these kinds of things in the west, what the WECC has done with the recommendations that were specifically addressed by NERC as a result of the report, the WECC has taken those NERC recommendations and we have put them in our disturbance log just like they occurred in the west, and those are being dealt with by WECC subcommittees to come up with ideas or mitigating measures for those. So that's in progress right now. And that's the short story.

MR. PALERMO: Thank you. Vegetation.

MR. NEAL: As you can tell, I've got a lot of passion around that; that's my job. I'm Mike Neal, if you needed to know that.

In regards to the August 14th outage there was four tree related outages. One was AEP, one was Synergy, one was in FERC, two were in First Energy. What came out of the FERC report was everything else that happened in the operational areas. Everything else, if the lines hadn't sagged into the trees, the cascading outage would not have happened.

Most people think of Arizona as a desert. We deal with over 8 million trees that we have to maintain in and around our utility corridors, SRP does. And when you look at even saguaro cactus, you're talking about siting new lines, and if you don't take that into consideration when you put lines in, people want to be environmentally conscious, but trees and power lines do not mix.

Can a cascading outage happen here? Yes, it can. And part of the reason we had that issue is a lot of federal agencies, especially, we deal with five national forests, 22 Forest Service districts, and they can dictate to the utility how much clearance they can or cannot give around utility lines.

And this isn't based on science, it isn't based on research, but there are sound vegetation management practices that utilities can maintain for safety, reliability, environmental stewardship, and customer satisfaction as well as cost management. And that should be the focus of any vegetation management program, if it's not reliability.

Good example is in Florida. I was called by an attorney who wanted me to be an expert witness for them because he was defending a family where four people got electrocuted by climbing a tree over the power line. The utility said they were only maintaining their vegetation for reliability purposes and not for safety. Unfortunately, they're doing that, management for reliability, you're -- the vegetation is dictating how you're maintaining that utility corridor. What's going to end up, in my opinion, they're going to pay big dollars, because vegetation management should be that five-prong approach in doing that.

Again, that's where I think we need the help from the ACC and other entities in regards to vegetation management activities. We need to have a consistent vegetation management approach. We put together an MOU that we're hoping FERC will take the lead to have other federal agencies sign that utilities do follow best management practices, because it's important because of interconnection, if we are not doing the same thing, we can have outages occur caused by vegetation.

I'm working with the governor on the Forest Service side health committee and some of my recommendations to her was that the state sign an MOU with utilities. She's going to do that and use her influence with the Western Governors Association. And at a meeting last week, as part of the forest health plan is that to encourage other states have utilities, called best management practice for utilities, and also encourage the governors to influence the federal agencies to work with utilities and following best management practices.

That's the short of it, so I'll stop there.

MR. JERRY SMITH: A quick question. FERC was requiring vegetation management plans be reported by all utilities, and Staff has seen a report from Southwest Transco and from Salt River Project.

My question is: Have the other utilities filed their reports, and if so, would you be willing to make those available to Staff?

MR. NEAL: Actually if you go to the FERC web page, TEP's there, SRP is there, ours is there, so we've all filed. And to be honest with you, it's interesting reading from my perspective. If you're a tree guy, you love this stuff.

MR. BECK: TEP did file with the Commission; it just hasn't hit your desk yet.

MR. PALERMO: How about large generator interconnection?

MR. EVANS: Bruce Evans, Southwest Transmission. I'll try to make this pretty brief, but the FERC issue, the large generator interconnection order, they called it Order 2003. It was issued on July 24th of 2003, but the implementation of that was delayed, I should say, for making a filing, until the 28th of January of this year.

Basically, FERC came out prior to that and said okay, we'll delay it, and then they issued an order on January 8th and said well, everybody's open access transmission tariff is going to be deemed to include the pro forma large generator interconnection agreement, and pro forma large generator interconnection procedures.

MR. PALERMO: Don't you love it when they do that.

MR. EVANS: What they're basically saying is one size fits all. That's what they did.

With regards to the impacts to that thing, one of the areas that we probably see here in Arizona is that we have a lot of jointly owned transmission, and so a lot of nonjurisdictionals own transmission together with jurisdictional entities, and so how is it that FERC can issue, if you will -- or force, I should say, maybe, I don't know how you want to put it -- this open access transmission tariff on a transmission line or any generator that wants to interconnect to a transmission line that's jointly owned by a lot of their revenues.

We have participation agreements with the entities that own a lot of these joint transmission lines between the entities. Those participation agreements are such that some of them, I would think that the -- anybody that wants to interconnect has to get approval from the owners, has to get approval from the engineering operations committee with this participation agreement. First it seemed to be pretty, I wouldn't say flippant, but maybe they were -- I know that Salt River Project specifically brought this issue up, and FERC didn't particularly like them bringing that issue up, and they basically said well, Salt River, you just go and talk to the other entity that owns part of that line and you just change your participation agreement. Well, it's not that easy to do that, so that is a huge, huge issue that we're not sure how all that's going to work out.

In addition is the nonjurisdictional transmission entities don't have to pay transmission credits in the same way that the jurisdictional entities do, so that's going to be a problem. How are you going to work all that out?

Another big area again has to do with pricing. With this order FERC allows these generators to interconnect and take what they call generator interconnection service, but they don't have to take network transmission service or any kind of transmission service. I don't know how they're going to price out some of those things, so there's some big issues with pricing that has to do with this order.

A lot of the utilities that made their filings, FERC said well, you can go ahead and make changes according to reliability, regional reliability practices, and you can also make changes according to whether it is consistent with or superior to the pro forma tariffs that we proposed, the pro forma large generator interconnection agreement and the large generator interconnection procedures.

Well, most of the entities that have made what we would call substantive changes have come back with rulings from FERC. FERC has said they're not going to accept a lot of those changes. I know that APS had about 170 substantive changes they wanted to make, and FERC said no, we're not really going to deal with those.

Nevada Power had over 200 substantive changes. They had 300 typographical changes and FERC basically said we're not going to deal with that. We'll maybe do it in a rehearing, but we're not going to deal with it right now.

With regards to the regional reliability practices, they did agree on some things. They did agree with the utilities here in the west that yes, we are following the WECC reliability procedures. We do have the southwest reserve sharing group, they did accept that as a reliability type entity, if you will. The RMS agreements that the entities signed with WECC, they accepted that as being a reliability criteria that was okay. They accepted the fact that there's WECC data power flow and stability that could be shared, it had to be done under WECC's confidentiality agreement.

But there were a lot of other items that weren't accepted. Most of the entities wanted to change the definitions contained in Section 1 of the large generator interconnection procedures in Article 1 of the large generator interconnection agreement. They wanted to substitute the word transmission provider with their own respective names throughout the text, and FERC said no, you're not going to do that.

There were a lot of other additional items that they had that were not changed.

MR. PALERMO: Are there any particular issues to Arizona?

MR. EVANS: Biggest one I think is the fact that there is transmission that was owned by jurisdiction, nonjurisdictional entities, and the pricing, how that's going to be priced, how the transmission credits are going to work, those are really the big issues.

MR. PALERMO: How might that affect the 500 kV circuits? I'm speaking from ignorance in terms of ownership. Are they jointly owned of nonjurisdictional entities in general?

MR. EVANS: Yes. Take the Western Area Power Administration; they own a lot of those lines. Salt River Project is a nonjurisdictional entity that owns a lot of those lines, so there will be some unique challenges implemented. There's not all the rehearing requests that entities are doing, have been done yet, but it's not likely they're going to change FERC's desire to, as they put it, provide a single uniformly applicable interconnection agreement or a one size fits all.

MR. PALERMO: Thank you very much.

And last I guess is the technical challenges regarding interconnection of renewable generation.

MR. MENDOZA: Steve Mendoza, Western Grid Energy Corporation. This is my presentation. Any questions?

Would you put up the very last slide. I've got several slides, we'll skip those. While he's doing that I'll talk, see if I can remember some of the things I wanted to say.

First of all, Western Energy Corporation, we have four viable wind sites that we are presently working. One is in Canada, awarded a 20 megawatt contract in Brunswick; 100 megawatt site in Tehachapi. We're negotiating with Southern California Edison; I applied for 100 megawatt interconnection with ISO. Two sites, one up in the Kingman area. In the Kingman area, we applied for 400 megawatt interconnection with Western Area Power Administration, and of course that's a very large wind project and we don't do 400 megawatts in one sweep, we start off with 10, 15, 20 megawatts, and build enough, if we can sell, go to 70, 80. We do think there's potential for over 400 megawatts, and the same as Tehachapi and the Palm Springs area, there's quite a bit of potential there.

The other site is by St. Johns, Arizona where we have a 15 megawatt PPA with Arizona Public Service Company, the first in the State of Arizona. So we do have resources here, viable wind resources. The benefits, of course, of wind is that the fuel source is free and it's environmentally very good. It doesn't use water, it doesn't create smoke or any of those other things.

Some of the environmental considerations, too, there used to be a lot of considerations or problems with birds in those types of things. Now the new units are really big, they can run 80 meters in diameter, 90 meters in diameter, they move at 18, 20, 21, 22 revolutions per minute, so they're big wide spaces between the blades and move very slow and very visible, so the problem with birds are not like they used to be. Since they're so large, they may take 10 to 30, 40, 20, 30 acres for a megawatt, so they're spaced pretty far apart. And the footprint, environmental footprint is pretty small. You have the access road, you may have a circle of 100 foot diameter around the base of the tower that you keep for bringing in cranes to do maintenance, those types of things.

MR. PALERMO: We have your slide up, maybe we can focus. I don't know if that's the one you wanted.

MR. MENDOZA: That's just the final slide. That's the end.

MR. PALERMO: Transmission issues related to wind power?

MR. MENDOZA: The problems that we have, once we get the wind data and the land, we have to get access to the transmission, which sometimes is difficult because it isn't always available. And that's one of the reasons I come into these meetings and try to participate, so that we know where the transmission is and maybe can be involved in the development.

One of the problems we have is that we can build the wind generation very rapidly. It can be done in a year. In fact, New Mexico just did their 200 plus megawatt wind farm over on the eastern part of New Mexico. They did it in less than six months from the word go to actually design and build and had it in service. Which the hardest part really is the electrical infrastructure, building the substations, getting the transformers takes a lot of lead time. It was a turnkey with Westinghouse, so that's one of the reasons they were able to do that; they bypassed all the drawing approvals and all those kind of things, I'm sure.

The other thing is, you know, it may take five to seven years for transmission to be built. You start looking at bigger wind projects, then we need access to the EHV system. If it has to be a new line, first of all we can't afford a whole line just for our project. Somebody else has to be involved also. But we could be looking at a wind project and it could be five to seven years before the line is there. So that causes a difficulty. The price of the higher voltage equipment is very expensive. It costs about a million dollars a megawatt to install wind. If you start going to the price of high voltage EHV transmission, it's very difficult to build a small one and get into that system unless there's something already there.

I'm trying to think without going through all the slides. From the utility's perspective on the other side, the things that you're concerned about tend to be things like harmonic flicker. Two issues. Manufacturers really improved the machines. They're telling us they have a way of mitigating this; they come with their own var support. They're trying to reduce causing harmonics and the flicker problem. It's both in our interests and your interests to be concerned about those issues and make sure those issues are taken care of up front. It doesn't do me good to tie a generator into your system, find out there's a voltage problem later, because you'll turn me off, and our investment is not making money to our -- it's best we do the studies up front, make sure there isn't harmonics or flicker, those type of things.

One of the things we're interested in is the potential outbreaks of the existing system. This gives us the ability to get involved in some of the expansion of that transmission. We are looking forward to that.

I think that that's probably about all I can remember.

MR. CHARTERS: Is this a Euro project?

MR. MENDOZA: This was the final slide. This is our new Colorado pump storage project. This actually is Kinder dike in Holland. These things are from the 17th century. They really are pumps they pump water out of that canal to the canal in the back. There's a water wheel inside. The water doesn't drain out. I just happened to visit there, I thought that was pretty interesting. The whole thing lifts two meters.

Any questions? I had a lot more stuff on the slide.

MR. PALERMO: If there's any questions, feel free to speak to him later. I'm not in a hurry to get out, except for my responsibility to you to try and end on time and to get out of the building. I'm not going anywhere till tomorrow morning, so it's not a problem to me. If you want to speak with me, if you want to speak to any of the panelists, I think we'll be around. Again, all of the material that you saw and at least some that we didn't see will be posted on the website in a day or two.

Thank you for your time and attention and for sticking it out. And to all of you, especially some of you that were on five or six panels, it seemed like during the day, to thank all of you for your participation. We found it very helpful to get this information. Thank you again.

(The proceedings concluded at 5:07 p.m.)

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, CECELIA BROOKMAN, Certified Court Reporter No. 50154 for the State of Arizona, do hereby certify that the foregoing printed pages constitute a full, true and accurate transcript of the proceedings had in the foregoing matter, all done to the best of my skill and ability.

WITNESS my hand this 14th day of July, 2004.

Cecelia Brookman

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